STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	**Docket No. 11-0280**
Proposed General Increase in Rates for Gas Service	:	
	:	**(cons.)**
The Peoples Gas Light and Coke Company	:	
	:	**Docket No. 11-0281**
Proposed General Increase in Rates for Gas Service	:	

INITIAL BRIEF OF THE
STAFF OF THE ILLINOIS COMMERCE COMMISSION

JOHN C. FEELEY
MICHAEL LANNON
NICOLE LUCKEY
Office of General Counsel
Illinois Commerce Commission
160 North LaSalle Street, Suite C-800
Chicago, IL 60601
Phone: (312) 793-2877
Fax: (312) 793-1556
jfeeley@icc.illinois.gov
mlannon@icc.illlinois.gov
nluckey@icc.illinois.gove

Counsel for the Staff of the
Illinois Commerce Commission

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Staff of the Illinois Commerce Commission ("Staff"), by and through its counsel, pursuant to Section 200.800 of the Rules of Practice (83 Ill. Adm. Code 200.800) of the Illinois Commerce Commission's ("Commission"), respectfully submits its Initial Brief in the above-captioned matter.

I. INTRODUCTION

A. Overview/Summary

North Shore Gas Company ("North Shore") and the Peoples Gas Light and Coke Company ("Peoples Gas") (individually, the "Company" and collectively the "Companies") filed new tariff sheets on February 15, 2011 in which the Companies proposed general increase in their natural gas rates. On March 23, 2011 the Companies' tariff sheets were suspended by the Commission and on July 7, 2011 the

Commission entered a Re-suspension Order extending the suspension to and including January 14, 2012. In due course, the Administrative Law Judges ("ALJs") assigned to this proceeding established a schedule for the submission of pre-filed testimony, hearings and briefs. (Notice of Administrative Law Judges' Ruling, April 13, 2011)

In response to the Company's filing, the following parties filed Petitions to Intervene, which were granted: The People of the State of Illinois *ex rel.* Lisa Madigan, Attorney General of the State of Illinois (the "AG"), Citizens Utility Board ("CUB"), the City of Chicago ("City") (collectively, "AG/CUB/City," Government and Consumer Interveners" or "GCI"); Illinois Industrial Energy Consumers ("IIEC"); Constellation NewEnergy – Gas Division LLC ("CNE-Gas"); Integrys Energy Services-Natural Gas, LLC; Interstate Gas Supply of Illinois ("IGS") and Vanguard Energy Services, L.L.C. ("Vanguard").

The following witnesses submitted testimony on behalf of the Staff of the Illinois Commerce Commission ("Staff"): Daniel Kahle (ICC Staff Exhibit ("Ex.") 1.0; ICC Staff Ex. 10.0), Mike Ostrander (ICC Staff Ex. 2.0; ICC Staff Ex. 11.0 corrected; ICC Staff Ex. 20.0), Theresa Ebrey (ICC Staff Ex. 3.0 corrected; ICC Staff Ex. 12.0 corrected); Sheena Kight-Garlisch (ICC Staff Ex. 4.0; ICC Staff Ex. 13.0), Michael McNally (ICC Staff Ex. 5.0 corrected; ICC Staff Ex. 14.0); David Brightwell (ICC Staff Ex. 6.0; ICC Staff Exhibit 15.0); Cheri Harden (ICC Staff Ex. 7.0; ICC Staff Ex. 16.0); Brett Seagle (ICC Staff Ex. 8.0; ICC Staff Ex. 17.0); David Sackett (ICC Staff Ex. 9.0; ICC Staff Ex. 18.0); and David Rearden (ICC Staff Ex. 19.0).

During the course of the proceeding, Staff proposed various adjustments and changes to the Companies' February 15, 2011 request. The Companies accepted certain of Staff's modifications and Staff withdrew others. A summary of Staff's final recommendations to the Commission in this proceeding for North Shore and Peoples Gas are attached hereto, respectively, as Appendix A and Appendix B. Also, attached as part of Appendix A and Appendix B are Staff's revised Revenue Requirements. For the reasons stated below, Staff's proposed adjustments should be adopted by the Commission.

B. Nature of Operations

1. North Shore

2. Peoples Gas

II. TEST YEAR (Uncontested)

III. REVENUE REQUIREMENT

The revenue requirement schedules attached to Staff's Initial Brief use the Companies' surrebuttal revenue requirements as their starting point. To the extent that Staff's proposed adjustments were rejected or only partially accepted by the Companies and reflected in the Companies surrebuttal revenue requirement, Staff's proposed adjustments are shown either in total or in part as an adjustment to the Companies' surrebuttal revenue requirement. Staff's proposed adjustments that were accepted in total by the Companies and therefore are reflected in the Companies' surrebuttal position are not shown as an adjustment on Staff's Initial Brief Revenue requirement schedules.

A. North Shore

Staff recommends a revenue requirement of $77,255,000 as reflected on page 1 of Appendix A to Staff's Initial Brief.

Staff recommends an increase to base rates of $394,000 (0.52%) and an increase of $134,000 (8.61%) to other revenues for a total increase of $528,000 (0.69%).

Staff's overall recommended increase is $7,819,000 less than the $8,347,000 increase requested by the Company in surrebuttal.

B. Peoples Gas

Staff recommends a revenue requirement of $555,180,000 as reflected on page 1 of Appendix B to Staff's Initial Brief.

Staff recommends an increase to base rates of $46,113,000 (9.41%) and an increase of $1,688,000 (9.78%) to other revenues for a total increase of $47,801,000 (9.42 %).

Staff's overall recommended increase is $64,809,000 less than the $112,610,000 increase requested by the Company in surrebuttal.

IV. RATE BASE

A. Overview/Summary/Totals

1. North Shore

Staff recommends a rate base of $185,050,000 as reflected on page 5 of Appendix A to Staff's Initial Brief. Staff's recommendation is $7,512,000 less than the $192,562,000 rate base requested by the Company in surrebuttal.

2. Peoples Gas

Staff recommends a rate base of $1,367,664,000 as reflected on page 5 of Appendix B to Staff's Initial Brief. Staff's recommendation is $105,189,000 less than the $1,472,853,000 rate base requested by the Company in surrebuttal.

B. Uncontested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Natural Gas Prices – Working Capital Allowance - Gas in Storage

In his direct testimony, Staff witness Seagle expressed a concern that Peoples Gas and North Shore relied upon out-dated gas pricing information to forecast its 2012 test year costs associated with its 13-month valuation of its working capital allowance for gas in storage and recommended the Companies use more recent gas prices. Staff Ex. 8.0, pp. 14-15. In response to Mr. Seagle's concern, Companies' witness Gregor updated the Companies' natural gas price by using the latest prices available from New York Mercantile Exchange (NS-PGL Ex. 21.0, p. 7) and Companies' witness Hengtgen in NS-PGL 23.5N and NS-PGL 23.5P updated the Companies' 13-month valuation of working capital allowance for gas in storage using this updated price. NS-PGL Ex. 23.0, p. 8. Mr. Seagle did not take issue with the Companies' updated 13-month valuation of working capital allowance for gas in storage. Staff Ex. 17.0, p. 9.

2. Plant

a. Specific Plant Investments – Warehouse at Manlove Field

In his direct testimony, Staff witness Seagle expressed a concern that Peoples Gas did not provide sufficient supporting documentation for Staff to verify the prudence and used and usefulness of the costs associated with the construction of a new warehouse at Peoples Gas' Manlove storage field ("Manlove"). Staff Ex. 8.0, p. 8. In Peoples Gas' rebuttal testimony Company witness Puracchio provided additional support for the inclusion of costs associated with the construction of a new warehouse; namely, a draft business case that demonstrated prudence and used and usefulness of the project. NS-PGL Ex. 33.0, pp. 3-5 and NS-PGL Ex. 33.1. Based on the additional information, Mr. Seagle withdrew his initial recommendation and instead recommended the Commission allow Peoples Gas to include costs associated with the new warehouse construction at Manlove, which results in an increase to Peoples Gas' base rates of $1,000,000 for 2012. Staff Ex. 17.0, pp. 5-8.

b. Pigging Well-Head Separator Project #1

Peoples Gas witness Puracchio in his direct testimony requested Commission approval to include in base rates the costs, $7,117,400 for 2011 and $6,500,000 for 2012, associated with the Pigging and Well-Head Separator Project #1. PGL Ex. 16.0, pp. 10-12; PGL Ex. 16.3; PGL Ex. 16.4; PGL Ex. 16.5; and PGL Ex. 16.6. Mr. Seagle determined that Mr. Puracchio had provided sufficient information to include the proposed project in base rates and did not dispute Mr. Puracchio's request. Staff Ex. 17.0, p. 12.

c. Pigging Well-Head Separator Project #2

Mr. Puracchio in his rebuttal testimony requested Commission approval to include in base rates the costs, $6,500,000 for 2012, associated with the Pigging and Well-Head Separator Project #2. NS-PGL Ex. 33.0, pp. 8-9 and NS-PGL Ex. 33.2. Mr. Seagle, in his rebuttal, determined that Peoples Gas had provided sufficient information to include the proposed project in base rates and did not dispute Mr. Puracchio's request. Staff Ex. 17.0, pp. 10-15.

d. Pipeline Heaters Replacement Project

Peoples Gas witness Puracchio in his rebuttal testimony requested Commission approval to include in base rates the costs, $3,300,000 for 2012, associated with the Pipeline Heaters Replacement Project. NS-PGL Ex. 33.0, pp. 9-10. Mr. Seagle, in his rebuttal, determined that Peoples Gas had provided sufficient information to include the proposed project in base rates and did not dispute Mr. Puracchio's request. Staff Ex. 17.0, pp. 15-17.

3. Accumulated Depreciation Expense on Forecasted Additions and Utility Plant in Service – 2010 Actual

Staff's proposed adjustments to Utility-Plant-in-Service - 2010 Actual were countered by alternative adjustments proposed by the Companies in their rebuttal position. Staff accepted the Companies' rebuttal position on this issue and withdrew its proposed adjustment. Staff Ex. 10.0, pp. 5 - 6.

4. Accumulated Deferred Income Taxes

a. Bonus Depreciation, Illinois State Income Taxes and Tax Accounting Method Changes

The Companies included the effect of bonus tax depreciation in 2011 and 2012 into their rebuttal position in determining the test year balance of Accumulated Deferred Income Taxes ("ADIT") deducted from plant in service. GCI Ex. 7.0, p. 4.

The Companies included the new State Income Tax rate in their rebuttal position. Since the Companies' rebuttal revenue requirements accounted for the new State income tax rate, Staff withdrew its proposed adjustments. Staff Ex. 10.0, p. 6.

The Companies did not reflect the impact of a tax accounting method change related to overhead capitalization for tax purposes because IRS consent for the requested accounting change was received too late to incorporate into the forecast of financial statements used in these cases. GCI Ex. 2.0, p. 11. The Companies reflected the impact of this change in their rebuttal position. NS-PGL Ex. 26.0, p. 5 and NS-PGL Ex. 26.0 CORRECTED, p. 13.

The Companies included the effect of bonus depreciation, the new State tax rate and the impact of a tax accounting method change related to overhead capitalization for tax purposes. No party contested these issues in rebuttal.

b. Use of Average Rate Assumption Method relating to Health Care Reform Legislation

c. Net Operating Loss – Tax Normalization

The Companies included a deferred tax asset related to Net Operating Losses ("NOL"). The NOL resulted from increased accelerated depreciation driven mostly by bonus depreciation and was reflected in the Companies' initial filings. NS-PGL Ex. 26.0, p. 16.

The Companies included a deferred tax asset related to NOL. No party contested this issue in rebuttal.

C. Contested Issues

1. Plant (All Subjects Relate to NS and PGL Unless Otherwise Noted)

a. Forecasted Test Year Capital Additions

i. Utility Plant in Service

The Companies updated their forecasted plant additions in their rebuttal testimony. Staff used the Companies' updated figures in computing its proposed adjustment in rebuttal testimony, and does not see the necessity of a separate adjustment.

ii. Capital Additions Related to Accelerated Main Replacement – AMRP (PGL)

GCI witness Effron proposed an adjustment to rate base for the rate of accelerated main replacement being slower than forecasted. Staff did not find fault with Mr. Effron's proposal, but finds its own analysis to be more appropriate. Staff's analysis included all of the Companies' budgeted capital expenditures rather than a single project as Mr. Effron's does. Staff Ex. 10.0, p. 15. While not individually identified, the accelerated main replacement project would be included in Staff's overall analysis.

Although Staff would support Mr. Effron's proposed adjustment, the Companies have accepted Staff's adjustment. NS-PGL Ex. 40.0 CORR., pp. 3 – 4. Accepting both Staff's and Mr. Effron's adjustments could result in double counting. If the Commission were to accept Mr. Effron's proposed adjustment, all or a portion of Staff's adjustment to forecasted plant additions should be removed from People Gas' revenue requirement.

b. Capitalized Incentive Compensation (see also Section V.C.1)

c. Non-Union Wages (see also Section V.C.2)

d. Original Cost Determination as to Plant Balances as of December 31, 2009

The Commission should approve $411,521,000 and $2,667,300,000 as the original cost determination of plant-in-service for North Shore and Peoples Gas, respectively, as of December 31, 2009. The original costs recommended by Staff are less than the Companies' proposed original costs because Staff does not include costs previously disallowed by the Commission. The Commission has disallowed capitalized incentive costs in Docket Nos. 07-0241/0242 and 09-0166/0167. The Companies argue that the disallowed costs should be included in original costs because the disallowed costs are contested issues on appeal for both the 2007 and 2009 rate cases. However, this would have the Commission contradict its own findings. Under the PUA the pendency of an appeal does not of itself stay or suspend a decision of the Commission. 220 ILCS 5/10-204. Therefore, the Commission should adjust original costs in accordance with its orders in the previous dockets 07-0241/0242 and 09-0166/0167. Staff Ex. 1.0 and 10.0, pp. 19 – 20.

2. Materials and Supplies – Computation of Associated Accounts Payable

The Commission should accept Staff's adjustment to reflect a more reasonable amount for the accounts payable for materials and supplies inventory. Staff's adjustment is more reasonable because it is based on actual purchases and takes into account the results of the Companies' lead/lag studies. Staff Ex. 3.0, Corrected, p. 27.

The Company, in its rebuttal testimony accepted an adjustment proposed by GCI witness Morgan, albeit with minor calculation corrections. NS-PGL Ex. 23.0, p. 11. While CGI witness Morgan's adjustment is an improvement over the Companies' proposal, Staff's adjustment more accurately reflects the accounts payable balance for material and supplies inventory.

Mr. Morgan's proposal uses the amount of purchases each month as a proxy for accounts payable balances which he then averages over 13 months; this proposal assumes that payment is made in 30 days. However his assumption regarding 30 days for repayment is flawed. The evidence indicates that payment is made in 42.44 days and 46.62 days for NS and PGL, respectively (Staff Ex. 12.0 Corrected, p. 19) not 30 days. Staff's adjustment is based on the 42.44 days and 46.62 days supported by the record and should be approved. If the Commission does not accept Staff's proposed adjustment, then it should consider Mr. Morgan's adjustment as an alternative, since it is an improvement over the Companies' proposal.

3. Gas in Storage – Computation of Associated Accounts Payable

The Commission should accept Staff's adjustment to reflect a more reasonable amount for accounts payable for gas in storage inventory. Staff's adjustment is more reasonable because it is based on actual gas purchased for injection into storage and the results of the Companies' own lead/lag studies. Staff Ex. 3.0 Corrected, p. 28.

Staff ‘s method of estimating the level of accounts payable associated with Gas in Storage is more accurate than the Companies’ method because it reflects the actual purchases and payments for gas placed into storage by the Companies. The Companies’ estimates presented on Schedule B-1.1 for each utility reflects amounts for accounts payable only in months in which the inventory balance increases; for those months of declining balances, no amount is included for accounts payable. Company Schedule F-8 clearly shows that injections are made every month of the year, thus accounts payable associated with gas in storage are created every month, not just in those months where the inventory balance reflects a net increase. Staff Ex. 3.0 Corrected, p. 28 and Schedules 3.5N and 3.5P.

The Companies argue that Staff’s adjustment is incorrect because it does not consider that the Companies account for gas in storage by the LIFO method of accounting for inventory. NS-PGL Ex. 23.0, p. 8. In response, Staff indicated that the method of accounting for inventory does not impact the balance recorded as accounts payable. Staff Ex. 12.0 Corrected, pp. 22-23. Staff also provided an explanation of the LIFO method of accounting for inventory and the mechanics of the LIFO Liquidation Credit which results from that accounting method based on the Companies’ discovery responses. Id., pp. 21-22. The Companies did not take issue with Staff’s characterization of that accounting. Due to the Companies’ argument regarding the LIFO method of accounting for inventory, Staff considered using the 12-month average of the LIFO Liquidation Credit as a proxy for the accounts payable, since those amounts are the liabilities recorded on the books of the utilities that are a direct result of the LIFO method of inventory valuation. However, Staff’s proposals for accounts payable which are based on the actual gas purchases and the delay in payment for those purchases are more accurate representations of the accounts payable associated with gas in storage inventory. Id., p. 23.

The Companies are the only party to take issue with Staff's adjustment in testimony. GCI witness Morgan initially proposed an adjustment to accounts payable associated with gas in storage inventory similar to his proposal for the accounts payable associated with Materials and supplies inventory. Mr. Morgan withdrew his adjustment in rebuttal testimony. GCI Ex. 6.0, p. 2.

4. Cash Working Capital

a. Pass-Through Taxes

The Commission should find that pass-through taxes have a revenue lag of zero days. Staff witness Kahle testified that revenue lag is, generally, the time lag between the Companies' cash outlays for the provision of service to the collection of cash from customers. Staff Ex. 1.0, p. 8.

Mr. Kahle further explained that Cash Working Capital is the amount of funds required from investors to finance the day-to-day operations of the Companies. Pass-through taxes are taxes that are added on to ratepayers' bills and collected by the Companies on behalf of a taxing body. While pass-through taxes are collected through the Companies' billing systems, they are not charges for utility service. Staff Ex. 1.0, p. 7.

Since pass-through taxes are not related to the provision of utility services, (i.e. not revenue), there is no lag between a delivery of utility service and the receipt of cash from customers. Accordingly, pass-through taxes cannot have a revenue lag. The

Commission has determined that pass-through taxes should have a revenue lag of zero in three recent rate cases: Commonwealth Edison Company Docket No. 10-0467; Ameren Illinois Utilities Docket Nos. 09-0309, 09-0307, and 09-0311 (Cons.); and Nicor Gas Docket No. 08-0363. In those cases the Commission stated the following:

> In our view, and after our analysis, we agree with Staff's position. We find it is proper to give the pass-through taxes zero revenue lag time in the CWC calculation. The fundamental idea lies in the theory that pass-through taxes are collected from the ratepayers and merely turned over by the Company to the taxing authority. Nicor seems to ignore the basic premise upon which CWC is based, as previously stated in the 2007 Peoples Gas Rate Case above. Since every dollar for pass-through taxes is collected from the ratepayers, the inflows and outflows earmarked for these taxes should be perfectly balanced. Thus the need for CWC should not arise with respect to pass-through tax transactions.

ICC Docket No. 08-0363, Order, March 25, 2009, at 11,

> As an initial matter, the Commission accepts Staff's argument that the utility has no "investment" associated with pass-through taxes. Since every dollar for pass-through taxes is collected from the ratepayers, the inflows and outflows earmarked for these taxes should be perfectly balanced. Thus the need for CWC should not arise with respect to pass-through tax transactions. This conclusion is consistent with prior Commission decisions. Nicor Docket No. 08-0363 at 11-12.
>
> Staff distinguishes pass-through taxes from other cash flows in that unlike other revenue, **pass-through taxes are not directly associated with the provision of utility service**. The Commission believes that Staff makes a legitimate point here. The Company would have us believe there is an additional and measurable cost to pass-through taxes but fails to illustrate how a tax that is completely ratepayer-funded could generate any costs or expense. This is simply not the case. The Commission finds that Staff's proposed adjustment to the CWC requirement must be accepted. [emphasis added]

ICC Docket Nos. 09-0306 et al. (Cons.), Order, April 29, 2010, at 54,

> The Commission agrees with Staff's interpretation as to the EAC/REC and GRT/MUT tax issues. For the EAC/REC tax, the utility shall remit all moneys

> received as payment to the Illinois Department of Revenue by the 20th day of the month following the month of collection. Under the GRT/MUT tax, this ordinance requires ComEd to file a monthly tax return to accompany the remittance of such taxes, due by the last day of the month following the month during which such tax is collected. Both the statute and ordinance requires ComEd to remit these pass-through taxes after they have been collected from customers. ComEd stated in its briefs that the Company correctly pays these taxes in the month following activity that occurs in a prior "tax liability" month. The Commission concludes that the CWC calculation for GRT/MUT pass-through taxes should reflect zero revenue lag days and 44.21 expense lead days and zero revenue lag days and 35.21 expense lead days for EAC/REC pass-through taxes as supported by Staff.

ICC Docket No. 10-0467, Order, May 24, 2011, at 47.

The Companies' own witness confirmed that pass-through taxes are not revenues. The Companies' witness Hengtgen states: "The revenue lag measures the number of days from the date service was rendered by Peoples Gas until the date payment was received from customers and such funds become available to Peoples Gas." PGL Ex. 7.0, p. 22. Mr. Hengtgen made an identical statement regarding North Shore Gas. NS Ex. 7.0, p. 19. By the Companies' definition, pass-through taxes remitted by ratepayers could not have a revenue lag since pass-through taxes do not represent payment for utility services. In accordance with the Companies' testimony, the Companies do not include pass-through taxes as revenue in their revenue requirements. Stated differently, the Companies propose to apply a revenue lag to something they themselves do not include as revenue.

Cash Working Capital is included in rate base to allow investors to recover the cost of financing operating expenses until operating revenue is collected. The collection of pass-through taxes is not the recovery of a cost of providing service; therefore, pass-through taxes are not included in the revenue requirement. Because ratepayers provide the financing for pass-through taxes, the Commission should not allow a revenue lag for pass-through taxes which would allow investors to earn a return on ratepayer provided funds.

The Commission should accept the Cash Working Capital levels recommended by Staff on page 11 of Appendices A and B to Staff's Initial Brief.

b. Prepayments (Uncontested)

Staff and GCI proposed different but similar adjustments to reflect prepayments in collection lag. The Companies accepted Staff's position in their rebuttal testimony. NS-PGL Ex. 26.0 CORRECTED, p. 14. Subsequently, GCI accepted the Companies' rebuttal position. GCI Ex. 6.0, p. 3.

c. All Other (Uncontested)

5. Retirement Benefits, Net

a. Pension Asset

The Commission should accept Staff's adjustment to remove the Pension Asset and associated Accumulated Deferred Income Taxes ("ADIT") from rate base. Staff updated the amount of the adjustment in rebuttal testimony to reflect the updated actuarial study as it was included in the Companies' rebuttal positions. The pension asset was created with funds provided by ratepayers, thus shareholders should not reap benefits from its inclusion in rate base. Staff Ex. 3.0, p. 3 Not only is such a conclusion supported by the evidence in the record in this case, it is also consistent with the Commission's conclusions about the pension asset in the 2007 and 2009 PGL rate cases. In both cases the Commission denied the inclusion in rate base of the pension asset. Staff Ex. 3.0 Corrected, pp. 4-5. Staff recognizes that the Commission is not bound by prior decisions:

> Initially we note that the decisions of the Commission are not *res judicata*. The concept of public regulation includes of necessity the philosophy that the Commission shall have power to deal freely with each situation as it comes before it, regardless of how it may have dealt with a similar or same situation in a previous proceeding. Thus like other administrative agencies, the Commission is free to change its standards so long as such changes are not arbitrary and capricious.

City of Chicago v. Illinois Commerce Commission, 133 Ill.App.3d 435, 440 (1st Dist. 1985) (citations omitted), and that the Commission must decide this case on the evidence in the record (220 ILCS 5/10-103, 10-201(e)(iv)(A)). However, on appeal, Commission decisions are entitled to less deference when the Commission drastically departs from past practice. Business and Professional People for the Public Interest v. Illinois Commerce Comm'n, 136 Ill.2d 192, 228 (1989). In this case the Companies did not provide any testimony explaining why the Commission should decide this issue differently for PGL. Staff Ex. 12.0 Corrected, p. 4. The Companies explained that the newly created pension asset for NS was funded from normal operating revenues collected from utility ratepayers. Staff Ex. 3.0 Corrected, pp. 3-4. While Company witness Phillips opines that customers did not supply the funds for the NS pension contribution, no evidence was provided to contradict the evidence provided in response to Staff data request TEE 9.02. The response to that data request indicates that the pension contribution results from "internally generated sources" (i.e. net cash from operations). Staff Ex. 3.0 Corrected Attachment B. Company witness Phillips also opines that due to pending appeals on this issue in the two prior PGL rate cases, the inclusion of the pension asset in the instant rate case is warranted; but she provides no new rationale or facts to support why the inclusion is "warranted". Id., p. 5. No Company witness provided surrebuttal testimony on this issue.

GCI witness Effron agrees with Staff's position on this issue and likewise recommends removal of the pension asset from rate base for both utilities. GCI Ex. 2.0, p. 10.

6. Accumulated Deferred Income Taxes –

a. 50/50 Sharing Related to Tax Accounting Method Changes

Staff does not support GCI's proposed adjustment related to the Companies' proposed 50/50 risk sharing for ADIT. Staff believes that having utilities assume all of the risk of uncertain tax positions would discourage utilities from taking tax positions that have some risk associated with them when such positions are appropriate and could benefit ratepayers. The Companies may benefit from ratepayer provided "free" or low cost capital in the short term, but if the Companies prevail, ratepayers will receive 100% of the benefit of reduced rate base in succeeding rate cases. Staff Ex. 10.0, pp. 23-24.

b. Derivative Adjustments from Contested Adjustments

Staff's position is that once a decision is made on the contested adjustments any derivative adjustments fall out of the formulae. Staff is not aware of any dispute over those formulae used to make the derivative adjustments.

D. Accumulated Depreciation (Uncontested Except for Derivative Adjustments from Contested Adjustments)

Staff's position is that once a decision is made on the contested adjustments any derivative adjustments fall out of the formulae. Staff is not aware of any dispute over those formulae used to make the derivative adjustments.

V. OPERATING EXPENSES

A. Overview/Summary/Totals

1. North Shore

Staff recommends total operating expenses of $64,153,000 as reflected on page 1 of Appendix A to Staff's Initial Brief. Staff's recommended level of operating expenses is $4,553,000 less than the $68,706,000 level requested by the Company in Surrebuttal ($65,235,000 pro forma jurisdictional plus an increase of $3,471,000).

2. Peoples Gas

Staff recommends total operating expenses of $467,513,000 as reflected on page 1 of Appendix B to Staff's Initial Brief. Staff's recommended level of operating expenses is $33,027,000 less than the $500,540,000 level requested by the Company in Surrebuttal; $452,491,000 pro forma jurisdictional plus an increase of $48,049,000.

B. Uncontested Issues

1. Physical Gas Losses

a. Modify Method of Accounting for Physical Gas Losses Associated with Manlove Field (PGL)

Staff witness Seagle recommended that Peoples Gas account for physical gas losses at its Manlove storage field in a different manner, specifically that Peoples Gas record the costs associated with physical gas losses as an Account 823 expense as opposed to recovering the costs through its purchase gas adjustment clause. Staff Ex. 8.0, p. 17. Company witness Puracchio accepted Mr. Seagle's recommendation. NS-PGL Ex. 33.0, p. 7. Company witness Moy provided testimony that demonstrated the impact of this recommendation resulted in an increase to Peoples Gas' Storage operation and maintenance expense of $121,000. NS-PGL Ex. 22.0, p. 17. Staff did not take issue with this calculation.

b. Amend written procedures for treatment of physical losses of gas from underground storage fields (PGL)

In his direct testimony, Staff witness Seagle recommended that the Commission's final Order direct Peoples Gas to collaborate with Staff to develop written procedures agreeable to both regarding the proper accounting of storage field activities as well as for Peoples Gas to amend its procedures to account for physical storage losses in Account 823. Staff Ex. 8.0, pp. 21-22. Mr. Seagle also recommended that Peoples Gas file its amended procedures on the Commission's e-docket system within six months of the date of the Commission's final Order. *Id*., p. 22. Peoples Gas witness Puracchio did not object to Staff's recommendation. NS-PGL Ex. 33.0, p. 7.

2. Distribution O&M

a. Expenses for locates, leak surveys, disconnects (O&M – PGL)

b. Building Costs (PGL)

3. Distribution O&M – adjustment to reflect costs that should have been capitalized instead of expensed

4. Distribution O&M - Inflation

5. Distribution O&M - Building Lease (PGL)

6. Customer Service and Information

a. Advertising

7. Administrative & General

a. Interest Expense on Budget Payment Plan

Staff proposed an adjustment to reflect the Commission ordered interest rate on budget payment plan balances (Docket No. 10-0719) rather than the Federal Reserve Board November 2011 1-year Constant Maturity Securities rate proposed by the Companies. Staff Ex. 3.0 Corrected, pp. 29-30. The Companies accepted Staff's adjustment in rebuttal testimony. NS-PGL Ex. 22.0, pp. 4-5, Lines 89-91.

b. Interest Expense on Customer Deposits

Staff proposed an adjustment to reflect the Commission ordered interest rate on customer deposits (Docket No. 10-0719) rather than the Federal Reserve Board November 2011 1-year Constant Maturity Securities rate proposed by the Companies. Staff Ex. 3.0 Corrected, p. 31. The Companies accepted Staff's adjustment in rebuttal testimony. NS-PGL Ex. 22.0, pp. 4-5, Lines 89-91.

c. Lobbying

Staff proposed adjustments to disallow expenses inherent with lobbying and related activity which were incorporated in the Companies' filing. Staff Ex. 2.0, p. 7. The Companies accepted Staff's adjustments in rebuttal testimony. NS-PGL Ex. 22.0, p. 4.

d. Social and Service Club Dues

Staff proposed adjustments to remove certain social and service club membership dues, which also included lobbying expenses, from the Companies' recoverable miscellaneous general expenses. Staff Ex. 2.0, pp. 7-8. The Companies accepted Staff's adjustments in rebuttal testimony. NS-PGL Ex. 22.0, p. 4.

e. Civic, Political, and Related

f. Charitable Contributions – Reclassification of 2012 costs

g. Inflation Factor Error-Miscellaneous Expense

i. Inflation Rate Update

Staff proposed an adjustment to update the revenue requirement for the May 2011 inflation rate data for the 2011 and 2012 calendar years (Staff Ex. 12.0 Corrected, p. 24) rather then the May 2010 inflation rate data used in the Companies' filings. Staff Ex. 3.0 Corrected, p. 33. The Company accepted Staff's adjustment in surrebuttal testimony. NS-PGL Ex. 39.0, p. 4.

ii. Inflation Factor Error

Staff proposed adjustments to reduce test year operating expenses to remove the impact of an inflation factor that was applied in error during the development of the 2012 budget. Staff Ex. 2.0, p. 9. The Companies accepted Staff's adjustments in rebuttal testimony. NS-PGL Ex. 22.0, p. 4.

h. Employee Benefits – Adjustment to Test Year Pension and Benefits Expenses to Reflect Most Recent Actuarial Report

i. Integrys Business Support Benefits Billed Expense

j. Advertising

Staff proposed adjustments to remove advertising expenses for sponsorship of community events and customer satisfaction research that are of a promotional, goodwill or institutional nature. Staff Ex. 2.0, pp. 8-9. The Companies accepted Staff's adjustments for removal of the expenses for sponsorship of community events in rebuttal testimony. NS-PGL Ex. 22.0, p. 7. In its rebuttal testimony Staff withdrew the remaining proposed adjustments for removal of the expenses for customer satisfaction research based on the Companies' disclosure that the subject costs were misclassified as advertising expenses and should have been reflected as miscellaneous customer accounts expenses. Staff Ex. 11.0 Corrected, pp. 3-4.

8. Depreciation Expense on Utility Plant in Service – 2010 Actual

The argument for Depreciation Expense on Utility Plant in Service – 2010 Actual is contained in Section IV B 3.

9. Current Income Taxes –

a. Bonus Depreciation, Illinois State Income Taxes and Tax Accounting Method Changes

The argument for Bonus Depreciation, Illinois State Income Taxes and Tax Accounting Method Changes is contained in Section IV B 4 a.

b. Reclassification of Income Taxes on Charitable Contributions

10. Invested Capital Tax (derivative adjustments)

The Companies did not contest Staff's proposal that invested capital tax will need to be updated to reflect the final Commission approved rate of return and rate base. The methodology to update invested capital tax is also uncontested. Invested capital tax adjustments are formula driven and should be calculated based upon the final Commission approved rate base, rate of return and pro forma operating income at present rates. Staff Ex. 10.0, pp. 15 – 16, NS-PGL Ex. 22.0 2nd CORRECTED, p. 4.

11. Interest Synchronization (derivative adjustments)

Staff, the Companies and GCI use the same methodology to determine the tax-deductible interest for ratemaking. Interest synchronization adjustments are formula driven and should be calculated based upon the final Commission approved rate base and weighted cost of debt. Staff Ex. 10.0, pp. 4 – 5; NS-PGL Ex. 22.0 2nd CORRECTED, p. 4.

12. Updated Inflation Rate

13. Rate 4 Revenues (NS)

C. Contested Issues

1. Incentive Compensation

The Commission should accept Staff's adjustment to limit incentive compensation costs to be recovered in base rates to those for which ratepayer benefit has been shown. Staff's adjustment was broken down into four subparts:

1) Disallowance of Executive Incentive plan costs related to shareholder-oriented goals, Company affiliate-performance goals, and goals tied to financial performance;

2) Disallowance of Non-Executive Incentive plan costs related to shareholder-oriented goals, Company affiliate-performance goals, and goals tied to financial performance;

3) Disallowance of Stock plan costs related to shareholder-oriented goals; and

4) Removal of capitalized incentive compensation costs previously disallowed by the Commission.

The Companies disagree with Staff's positions under the first three subparts above. While reserving their rights under cases pending in the Appellate courts, the Companies do not take issue with the amounts of capitalized incentive compensation costs previously disallowed by the Commission. In their overall argument regarding Staff's disallowance of Incentive Compensation costs, the Companies describe what the Incentive Plans provide for the **utilities.** According to the Companies, the Incentive Plans:

- Fulfill their need for a portion of compensation to be incentive based;

- Support their philosophy to establish market-based total compensation programs; and

- Allow them to be competitive in the labor market. NS-PGL Ex. 25.0, p. 4, Lines 71-82.

None of these reasons address the ratepayer benefit required by the Commission in prior cases for such costs to be recovered from ratepayers. Staff Ex. 3.0 Corrected, pp. 21-23, Lines 482-564.

a. Executive Plan

Staff recommends disallowance of 96% and 97% respectively of the Peoples Gas and North Shore Executive Incentive compensation Plan costs because:

a. 70% of the payout is based upon the achievement of the annual Integrys Group Consolidated Diluted Earnings Per Share – Adjusted;

b. 27% of the remaining Executive Plan expense is an estimate of the performance goals that are based on the achievements of PGL and NS affiliates; and

c. 50% of the balance which is tied to Integrys Energy Group's net income. Staff Ex. 3.0 Corrected, pp. 9-11.

The Companies counter that since the earnings per share has both a cost side and a revenue side, its costs should not be disallowed from recovery. The Companies then offer an example of cost savings (top executives foregoing the 2009 general wage increase) (NS-PGL Ex. 25.0, p. 5) but, as the evidence demonstrates, that "savings" had “de minimis” impact on overall costs of each utility or the actual payout under the incentive plan. Staff Ex. 12.0 Corrected, pp. 6-7.

The Companies next explain that comprehensive programs provided at the corporate level reap benefits to all the affiliates and thus the costs of the incentive plan that may result from the programs should be borne by all the affiliates regardless of the benefit to each affiliate on a stand-alone basis. NS-PGL Ex. 25.0, pp. 6-7. However, the Companies have not indicated the level to which each affiliate benefitted from the various programs discussed.

The Companies argue that Integrys has consistently met its EPS targets and it is reasonable to expect that pattern to continue. Id., p. 8. Staff’s concern is not so much whether the target will be met but rather that it ***must*** be met in order for the payout to not be decreased, thus tying payout again to a financial target. Staff Ex. 12.0 Corrected, p. 8.

b. Non-Executive Plan

Staff recommends that 50% of the Non-Executive Plan be disallowed from recovery because it is based on the financial goal of meeting targeted O & M budget levels and these goals have not been shown to benefit ratepayers. Staff Ex. 12.0 Corrected, pp. 10-11. The Companies argue that controlling costs by meeting certain budgeted target levels for O&M costs would benefit ratepayers and has been accepted in prior rate case Orders. NS-PGL Ex. 25.0, pp. 10-12. During cross-examination on this issue, Staff witness Ebrey stated that while some showing of ratepayer benefit may have been made in those cases, no such evidence has been provided to support this claim by the Companies in the instant case. Tr., August 30, 2011, pp. 235-239. Ms. Ebrey further noted that the Commission has recently rejected a budget for use as "an appropriate standard to judge utility performance." Staff Ex. 3.0 Corrected, pp. 13-14.

c. Omnibus Incentive Compensation Plan

Plan costs under the Omnibus Incentive Compensation Plan should be disallowed from recovery since they are based on financial measures that primarily benefit shareholders and not ratepayers. The Companies acknowledged in discovery that there have been no changes to these plans since the last rate case. Staff Ex. 3.0 Corrected, p. 15. Information provided in the 2009 case explained that the three stock plans are awarded based on the following financial outcomes:

1. The Integrys Restricted Stock Unit Award plan is valued solely using the stock price of Integrys Energy Group, Inc.

2. The Integrys Performance Stock Right Agreement plan is valued using a model comparing Integrys Energy Group, Inc.'s stock price, shareholder returns, total stock return volatility and dividend yield with a peer group.

3. The Integrys NonQualified Stock Option Agreement plan is valued using a model comparing Integrys Energy Group, Inc.'s stock return volatility and dividend yield.

Docket 09-0166/-0167, Staff Ex. 1.0, pp. 15 – 16.

These plans have already been considered and deemed not recoverable in base rates in the 2009 rate case. The Companies have provided no reason for the Commission to make a determination now that is inconsistent with the treatment of these costs in the prior rate cases.

The Companies' only argument regarding this subpart is that the plans are necessary to attract and retain a qualified and motivated workforce. No explanation was provided to explain how the metrics under these plans result in benefits to the ratepayers.

d. Capitalized Incentive Compensation costs previously disallowed

In the Companies' last two rate cases, Docket Nos. 09-0166/09-0167 (Cons.) and 07-0241/07-0242 Cons., the Commission disallowed a portion of the Companies' capitalized incentive compensation. 09-0166/0167 Order Appendix A, p. 13/ Appendix B, p. 11 and 07-0241/0242 Order pp. 66-67. The Companies did not make any entries, though, to remove the disallowed amount from rate base. Companies' responses to Staff DR TEE 1.11. Therefore, the previously disallowed capitalized incentive compensation is included in the test year rate base and should be removed in accordance with the Commission's prior order. Staff Ex. 12.0 Corrected, p. 16.

2. Non-union Base Wages

The Commission should accept Staff's adjustment to reduce the amount of non-union wage escalation for the test year to 3.0% for 2011 and 2.30% for 2012 because these are more reasonable estimates based on the evidence. The amount Staff proposes for 2011 is based on the actual amount of increase granted effective February

2011. The amount Staff proposes for 2012 is based on the Survey of Professional Forecasters Q3 2011 that was released on August 12, 2011.

In rebuttal testimony the Companies offered the World at Work Salary Budget Survey as support for the wage projections of 3.9% for both 2011 and 2012 increases. Staff's review of the July 2010 and July 2011 surveys indicated that increases for the 2011-2012 periods are projected to be fairly flat at 2.9-3.0% with **only the highest performers** potentially expecting increases as high as 4.0%. Staff Ex. 12.0 Corrected, p. 14. The Company is projecting all wages to increase at an average level of 3.9%, which indicates that the high performers for the utilities would be receiving increases even higher than the survey indicates. Staff also noted that historic rate increases granted by the utilities for the period of 2008 through 2010 were 3.8%, 3.72% and 2.0%, while the Companies projected 4.2% for 2009 and 2010 in the 2009 rate case filings. Staff Ex. 3.0 Corrected, p. 25. The increase granted in the 2009 rate cases was 2.2%. Order, January 21, 2010, Docket Nos. 09-0166/0167, p. 61.

Staff bases its recommendation on the Survey of Professional Forecasters rather than World at Work Survey results since it is a more forward-looking study projecting 2011-2015 increases rather than the single year projected in the World at Work survey. The Companies cited to the Bureau of Labor Statistics Employment Cost Index as support in their rebuttal position. Staff opines that even though it is a backward looking study, the results also indicate a 3.0% wage increase for the utility industry in the most recent 12 months reported as of July 6, 2011. Staff Ex. 12.0 Corrected, pp. 16-17.

3. Headcounts

GCI witness Effron proposed an adjustment to reduce Peoples Gas test year employees by 31 to reflect the number that has been in place throughout 2009 and 2010 instead of the increase forecasted by the utilities. GCI Ex. 2.0, p. 13. During cross examination, Staff witness Ebrey agreed that the actual number of employees has not increased as forecasted, but she observed that there is a certain amount of overlap between her adjustment for nonunion wage increases and Mr. Effron's adjustment to test year employee headcount. Ms. Ebrey's adjustment is limited to the amount of nonunion wages based on the actual payroll for the year 2010, thus does not reflect an increase in the number of nonunion employees. Tr., August 30, 2011, p. 244. A comparison of the total nonunion payroll for 2010, $54,158,000 (Staff Ex. 12.0 Corrected, Schedule 12.3P, p. 2), with the total projected 2010 payroll $ 78,627,000 (Company Schedule C-11.1) indicates that 68.9% ($54,158,000 divided by $78,627,000) of total payroll dollars are to nonunion employees, leaving 31.1% (100% minus 68.9%) to union employees. Therefore, if the Commission determines a decrease in headcount is warranted beyond that already reflected in Staff's wage increase adjustment, only 31.1% of GCI witness Effron's adjustment should be approved.

4. Self-Constructed Property

GCI Witness Effron proposes to disallow $1.722 million of Peoples Gas' test year operating expenses for self-constructed property costs no longer being capitalized because of a change in policy to be consistent with other Integrys companies. Mr. Effron argues that the expense for self-constructed property should be treated as an addition to plant and depreciated. GCI Exhibit 2.0 Corrected, pp. 26-27. Staff agrees with Peoples Gas that indirect general and administrative type costs have a much less direct relationship to capital projects compared to more direct types of overhead such as engineering and operations management who work directly on capital projects. The direct type of overhead costs will continue to be capitalized. Peoples Gas, in response to Staff DR JMO 8.05, disclosed that none of the other Integrys regulated utilities capitalized the subject indirect overhead costs. The policy of capitalizing the subject indirect overhead costs was implemented mainly to assist the Companies' tax department in meeting requirements under the Tax Reform Act of 1986. The tax department has now filed with the Internal Revenue Service for a different means of calculating such indirect costs. Due to the above reasons, the Companies in 2012 will begin to expense certain indirect overhead costs of self constructed property. Therefore, Staff believes that Mr. Effron's proposed adjustment for self constructed property is not necessary. Staff Ex. 11.0 Corrected, pp. 10-11.

5. Uncollectibles Expenses – Use of Net Write-Off Method

Staff recommends that the Commission establish uncollectible expense percentages of 0.5936% for North Shore Gas and as 2.7927% for Peoples Gas. Staff Ex. 1.0, p. 23. As discussed in Section VIII.A., Riders UEA and UEA-GC of this brief, Staff has recommended that the Commission order the Companies to switch to the net write-off method in Rider UEA. It the Commission orders the Companies to switch to the net write-off method in Rider UEA, the net write-off method must also be used to determine the utility's uncollectible amount in rates during the instant proceeding. Id., p. 22. Section 19-145 (a) of the Act, Automatic adjustment clause tariff; uncollectibles, states:

> The Commission may, in a proceeding to review a general rate case filed subsequent to the effective date of the tariff established under this Section, **prospectively switch from using the actual uncollectible amount set forth in Account 904 to using net write-offs in such tariff, but only if net write-offs are also used to determine the utility's uncollectible amount in rates**. In the event the Commission requires such a change, it shall be made effective at the beginning of the first full calendar year after the new rates approved in such proceeding are first placed in effect and an adjustment shall be made, if necessary, to ensure the change does not result in double-recovery or unrecovered uncollectible amounts for any year (emphasis added).

220 ILCS 5/19-145

The argument for adopting the Net write-off method in Rider UEA and Rider UEA-GC is contained in Section VIII.A.

6. Administrative & General

a. Injuries and Damages Expenses

GCI Witness Effron proposes to disallow $3.0 million of Peoples Gas' test year operating expenses for injuries and damages expenses. Mr. Effron believes that Peoples Gas has not adequately supported the increase in billings from IBS for injuries and damages expenses from 2009 to the 2012 future test year. GCI Exhibit 2.0 Corrected, pp. 28-29. Peoples Gas, in rebuttal testimony, points out that Mr. Effron focused solely on billings from IBS and not total injuries and damages expenses. Schedule C-4 for Peoples Gas shows that the increase for total injuries and damages expenses from 2009 to 2012 was $0.6 million or 5.13%. People Gas' Witness Gregor, in rebuttal testimony, identified the impact of inflation on medical costs for workers compensation claims as the primary causal factor for the increase in injuries and damages expenses from 2009 to 2012. NS-PGL Ex. 21, p. 11. Peoples Gas' responses to Staff DRs JMO 2.04 and JMO 2.05 mirrors Ms. Gregor's rebuttal testimony and adequately support the increase in injuries and damages expenses from 2009 to 2012. Therefore, Staff believes that Mr. Effron's proposed adjustment is not necessary. Staff Ex. 11.0 Corrected, p. 12.

b. Adjustment to Account 921- Office Supplies and Expenses

GCI Witness Effron proposes to disallow $2.892 million of Peoples Gas' test year operating expenses for office supplies and expenses because Peoples Gas has not adequately supported the increase in mobile data costs, from 2009 to the 2012 future test year. GCI Exhibit 2.0 Corrected, pp. 26-27. In response, Peoples Gas has identified a misclassification of budget amounts between Account 921, Office Supplies and Expenses and Account 903, Customer Records and Collections Expenses. $3.1 million that was budgeted to Account 921 should have been budgeted to Account 903. This budgeted amount represents costs related to the customer billing system and should have been budgeted to the account, Account 903, where they were booked in 2009. NS-PGL Ex. 21, p. 12. Staff believes that the shift of the customer billing system budget amount between the two expense accounts is an appropriate explanation and negates the need for an adjustment to reduce test year operating expenses. Staff Ex. 11.0 Corrected, p. 10.

c. Rate Case Expenses

i. Rate Case Expenses – Docket Nos. 11-0280/0281 (cons)

The Commission should accept Staff's adjustments to reflect a reasonable amount of rate case expenses ($2.536 million for North Shore and $3.731 million for Peoples Gas) to prepare and litigate Docket Nos. 11-0280/0281 rate case filings. The Companies agree with Staff that the original rate case estimates should be adjusted accordingly based on the most recent actual data available and any change in assumptions during the course of the proceeding. The Companies' rate case expenses adjustments in surrebuttal testimony were based on the following arguments: (1) use the most recent actual data – July 2011, (2) Staff in rebuttal testimony calculated incorrectly the adjustment to amortization expense for current rate case expenses, and (3) Staff in rebuttal testimony should not have excluded incentive compensation from rate case expenses. NS-PGL Ex. 22.0, pp. 7-9.

Staff agrees with the Companies' on points (1) and (2) above and addressed point (1) in supplemental rebuttal testimony, Staff Ex. 20.0, pp. 2-3, and point (2) in corrected rebuttal testimony. Staff Ex. 11.0 Corrected, pp. 3-4. However, Staff disagrees with the Companies on point (3). The basis by which Staff's adjustments excludes incentive compensation from rate case expenses follows Staff position for disallowing Non-Executive Incentive plan costs from being recovered in base rates as documented in Section V. C. 1, Incentive Compensation. That reason being the costs are related to shareholder oriented goals, Company affiliate-performance goals, and goals tied to financial performance. Staff Ex. 11.0 Corrected, pp. 6-7. The adjustments recommended by Staff to reflect a reasonable amount of rate case expenses, excluding incentive compensation expenses, for Docket Nos. 11-0280/0281 are appropriate and should be adopted by the Commission.

ii. Amortization of Rate Case Expenses associated with Docket Nos. 09-0166/0167 (cons)

The Commission should accept Staff's adjustments to amortize the remaining actual costs incurred, excluding any rehearing costs, for the prior rate case expenses in Docket Nos. 09-0166/0167. The Companies' calculation of amortization expense of the prior rate case expenses is based on amounts which include costs for rehearing which were not previously approved by the Commission. The rate case expenses used in the calculation should be the lesser of the actual amounts incurred through the preparation of the compliance filing after the final order has been issued by the Commission or the amounts the Commission approved in the prior rate cases. The actual incurred rate case expenses, excluding rehearing costs, for Docket Nos. 09-0166/0167 were less than the amounts approved by the Commission. Staff Ex. 11.0 Corrected, p. 8. The adjustments recommended by Staff to amortize the remaining actual costs incurred, excluding any rehearing costs, for Docket Nos. 09-0166/0167 are appropriate and should be adopted by the Commission.

iii. Normalization of Rate Case Expenses

GCI Witness Morgan recommends that rate case expenses should be treated as a normalized operating expense and not afforded regulatory asset treatment. GCI Exhibit 1.0 Corrected, p. 22. The Companies do not agree with Mr. Morgan's recommendation to normalize annual rate case costs as base rate operating expenses. The Companies cite the Commission Order in ComEd's most recent rate case, where the Commission "declined to "normalize" ComEd's rate case expense. The term "normalize" is one that is traditionally associated with the expenditures for day-to-day operations, like office supplies. Rate case expense is not a day-to-day operational cost; it is an extraordinary cost that occurs sporadically." ICC Docket No. 10-0467, Order, May 24, 2011, at 68.

Staff does not support Mr. Morgan's recommendation at this time and agrees with the Companies' position, which is consistent with the Commission's prior conclusion in Docket No. 10-0467 that rate case expense is an extraordinary cost that occurs sporadically and should be afforded treatment as a regulatory asset with subsequent amortization. It has been the general practice of the Commission to provide recovery of the cost of the current rate case and the unamortized cost of prior rate cases as an operating expense in the revenue requirement of the current rate case. However, the Commission ordered the initiation of a rulemaking regarding rate case expense in Docket No. 10-0467 and it is possible that this general practice may be an issue in that proceeding. It would not be appropriate to revise the general practice before the Commission has the opportunity to consider various alternatives in the rulemaking. Staff Ex. 11.0 Corrected, pp. 13-14.

d. Gas Transportation Administrative Costs

e. Solicitation Expense

The Commission should accept Staff witness Sackett's proposed adjustment to the expenses billed to the Companies from their affiliated service company Integrys Business Support ("IBS"). IBS failed to charge another affiliate, Peoples Energy Home Services (PEHS) for services IBS performed for it related to the Pipeline Protection Plan ("PPP") according to its effective affiliate agreements and failed to credit the Companies for those revenues. The Companies' agreement with IBS provides that IBS charge the Companies for expenses less revenues provided to IBS by other parties. The affiliate agreement between IBS and non-utility affiliates provides that these services may be performed but that the charges must be at Fully Distributed Cost ("FDC") basis. This failure by IBS to recognize revenues for services it provides to certain affiliates, i.e.

PEHS, has the end result of IBS over charging the Companies for services provided by IBS to the Companies.

The Pipeline Protection Plan ("PPP")[1] is a warranty product offered to Peoples Gas and North Shore ratepayers presumably to protect them against the risk of having to pay for repairs to exposed gas lines within their homes. PPP costs customers $2.95 per month and covers repairs up to $300 per incident. It is a product owned by the Companies' affiliate Peoples Energy Home Services (PEHS)[2], Staff Ex. 9.0, Attachment D: Companies responses to Staff DR DAS 2.09, and has been offered to these ratepayers since April 2004. Companies responses to Staff DR DAS 2.02. Staff Ex. 9.0, p. 33. For the years 2005 – 2010, there has been an average of 23,553 PPP customers for Peoples Gas and 3,582 for North Shore. Staff Cross Ex. 15, pp. 1-4: Companies responses to Staff DR DAS 2.06 Att. 01.

Both Companies provide services to support PPP. These services include the repairs of all leaks[3], Companies responses to Staff DR DAS 6.01, and the billing of the $2.95-per-month charge. Companies responses to Staff DR DAS 2.03. From 2004 – 2007, the Companies provided solicitation of their ratepayers and responses to customer inquiries. Staff Ex. 9.0, p. 33. However, another affiliate of the Companies, Integrys Business Support ("IBS") now provides these "Customer Relations" services for both the Companies and PEHS. NS-PGL Ex. 21.0, p. 4.

[1] This product is also called Peoples Energy Protection Plus.

[2] This affiliate is sometimes referred to as Peoples Home Services (PHS).

[3] These repairs include install flexible connectors with shutoff, install shutoff, repair leaks in piping. Companies response to Staff DR DAS 6.01.

For the years 2005 – 2010, there has been an average of $818,807 annually collected on behalf of PEHS for Peoples Gas and $136,607 for North Shore. Staff Ex. 9.0, Attachment E: Companies revised corrected responses to Staff DR DAS 2.10 and Att. 01.

Currently the Companies provide these services under the Services and Transfers Agreement ("STA") that was approved in Docket No. 06-0540. This agreement explicitly authorizes the billing repairs and solicitation. Staff Ex. 9.0, Attachment F: Companies responses to Staff DR DAS 2.08 and Att. 03, p. 4. The Companies must charge their affiliate according to the "pricing mechanism approved by the Commission" or, if none exists, the Fully Distributed Cost ("FDC") of providing that service. Staff Ex. 9.0, Attachment F, p. 6.

For the years 2005 – 2010[4], there has been an average of 276 repairs annually on behalf of PEHS for Peoples Gas and 38 for North Shore. Staff Ex. 9.0, Attachment H: Companies to Staff DR DAS 2.12 Att. 01. This results in an annual PPP repair percentage of 1.2% for Peoples Gas and 1.0% for North Shore. From 2005 – 2010 Peoples Gas and North Shore received an average of $9,757 and $1,050 annually respectively from PEHS for repairs for PPP customers. Staff Ex. 9.0, Attachment E. This amounts to an average of $35.35 and $28.04 per repair and an actuarial cost of $0.41 and $0.29 per PPP customer annually.

Staff witness Sackett defines two concepts in his direct testimony to explain the margin on PPP. He defines "actuarial cost" as average cost of having to pay for the repairs. The remaining amount of the revenues is the "risk premium." Mr. Sackett

[4] These are the only years with 12 months of data.

defines the risk premium as "the amount that a customer pays over the actuarial cost in order to mitigate the risk of the financial loss. The risk premium covers costs not related to repairs and the margin on the product." Staff Ex. 9.0, p. 36. Since PPP Customers pay $35.40 annually for this product, the risk premium is $34.99 for Peoples Gas and $35.11 for North Shore. These concepts and the underlying numbers are unrefuted and they demonstrate that these products are over priced. Thus the margin is a good starting place for an adjustment given the Companies utter failure to credit ratepayers for the full costs incurred as set forth below.

The Companies insist that their agreements with their affiliates require that charges must be at FDC and that the no adjustment is needed because of they have been billing appropriately or that an adjustment must be for the FDC even though the agreements have been repeatedly disregarded. By their own admission, the Companies have failed to abide by Commission-ordered agreements. Ms. Gregor claims in her rebuttal testimony that they are in compliance. "According to the Commission approved STA, which is the affiliated interest agreement under which the Utilities charge PEHS for services, the Utilities are to bill PEHS at the Fully Distributed Cost for providing that service. *The Utilities are billing according to the STA*. NS-PGL Ex. 21.0, p. 5, emphasis added. This is not the case. The Companies solicitation was below FDC, their repair billing was below FDC and their billing was below FDC. Further, in her surrebuttal testimony Ms. Gregor acknowledges that the Companies have not been billing according to the STA stating, "[I]t has been determined that the Utilities have missed billing overhead costs related to benefits and payroll taxes to PEHS from 2008-2010." NS-PGL Ex. 38.0, p. 10-11.

Additionally, the Companies' affiliates have failed to abide by other agreements. "According to the Commission approved Master Non-Regulated Affiliated Interest Agreement ("AIA") which now applies to billing by the Customer Relations area to PEHS, the amount billed must be at cost….the solicitation expenses that should have been charged to PEHS by IBS and, thus, should have reduced the expenses charged by IBS to the Utilities by the same amount." NS-PGL Ex. 21.0, p. 5. Last, the Companies have failed to include the appropriate amounts in previous rate case test years for customer relations, repairs and billing as discussed further below. The Commission should not feel obligated to respect pricing provisions of agreements that the Companies do not themselves respect.

Issues related to treatment of solicitation services for PEHS has a considerable history. The Companies provided solicitation and other customer relations services to PEHS from 2004-2007. During this time customer relations services were covered by the Services and Transfers Agreement ("STA") or its predecessor. Under these agreements, all services had to be provided at the "pricing mechanism approved by the Commission" or, if none exists, the fully distributed cost ("FDC") of providing that service. Staff Ex. 9.0, Attachment F, p. 6.

In 2008, the Companies transferred the customer relations portion of their utilities to another affiliate, Integrys Business Support ("IBS"). According to Ms. Gregor, transactions between the two affiliates (PEHS and IBS) are subject to a Master Non-Regulated Affiliated Interest Agreement ("AIA"). NS-PGL Ex. 21.0, p. 5. This agreement requires that IBS charge PEHS at FDC. The amount that IBS charges to PEHS is important because during a rate case, the Companies pay the residual amount not paid to IBS by other affiliates. NS-PGL Ex. 21.0, p. 4. The Companies current position is that the test year includes a credit to the Companies in the amount of $16,000. There are eight reasons why this position should be rejected by the Commission.

First, it is implausible to conclude that the Companies included a credit to ratepayers for the amount that IBS neglected to charge to PEHS in the test year presented to the Commission in the spring of 2011. According to the Companies current position, their affiliate, IBS, neglected to charge PEHS for these services despite the requirement of the governing agreement. However, the Companies claimed they remembered to include this estimate in their respective test years that were provided to the Commission in the Companies' direct case.

Second, the Companies' witness Ms. Gregor admits that, aside from her testimony, there is no evidence that the test year includes *any* billing amount from IBS to PEHS, much less the amount she claims is included. When asked to demonstrate that this amount was included in the test year, she responded that since this is a billing from IBS to PEHS, it reduces the amount of billings to Peoples Gas and therefore will not show up as an identifiable amount on any of Peoples Gas' [and North Shore's] schedules." Staff Cross Ex. 15, p. 9: Companies response to Staff DR DAS 13.03e. However, this is an inadequate response because it puts the Commission at the mercy of the Companies to correctly identify these partial amounts within the test year. Further, there should be some basis for this partial amount and for the total numbers of which this amount is a part.

Third, Companies' witness Ms. Gregor admits that there is no basis in the record for the inputs used in the estimated percentages used in the derivation of the

Companies calculated amount of costs to provide services to other affiliates. As she looked at a document that she claimed was the basis for the test year amount, Ms. Gregor was asked if the basis for the components of the estimate were on the record. She admitted that the cost of each call ($2.63), the number of calls per day (200) and the percentage of time spent on solicitation (5%) had no basis in the record. Tr. pp. 910-911, September 2, 2011. Therefore, the estimated allocation percentage of 0.2% for IBS's customer relations costs is completely unsubstantiated and the estimates and any test year allocations that result from these numbers should be rejected by the Commission.

Fourth, the Companies failed to provide any basis for test year credit to the Companies as Companies' alleged test year estimate is based on a study that has not been provided. When asked to provide the basis for this amount, Ms. Gregor maintained that it was shown in her earlier response to Staff DR DAS 10.01 Attachment 01, p. 5,Staff Ex. 18.0, Attachment F, which shows the derivation of the 2011 estimate. Tr. pp. 902-907, September 2, 2011. However, the percentage of call center costs to be allocated to PEHS in the test year in DAS 10.01 is 0.221% and in the workpaper, the percentage is 0.235%. Staff Cross Exhibit 13, not 0.2% as Ms Gregor has contended. The Commission should reject any test year number without an actual basis.

Fifth, in the Companies' rebuttal testimony they argued that the test year did not include this amount and that an adjustment to the IBS expenses is warranted. The Companies have acknowledged, despite assurances that IBS is *required* to charge FDC, PEHS was not charged at all for these services from 2008 until sometime in 2011. Staff Ex. 18.0, Attachment G: Companies responses to Staff DRs DAS 9.09. This period includes the previous rate case's test year, which does not reflect any solicitation charges. In their rebuttal testimony, the Companies admitted that they had failed to include a credit to the Companies' IBS expenses. Ms. Gregor estimated that the adjustment should have been about $71,068 for the test year. NS-PGL Ex. 21.1 P and 21.1N. According to this logic, the Companies somehow remembered to include this estimate in the respective test years provided to the Commission with the Companies' direct case but subsequently forgot this adjustment in their rebuttal testimony. The Companies provided no explanation as to why their surrebuttal testimony directly contradicts their rebuttal testimony.

Sixth, the Companies' rebuttal testimony estimated that the amount of test year customer relations expenses for PEHS was $71,068, an amount more than four times the estimate allegedly included in the test year amount. The fact that even this understated amount is significantly more than the final $16,572, which the Companies have alleged to have been included all along, casts doubt on the final estimate.

Seventh, the Companies FDC charges for 2005-2007 are based on Full Time Equivalents ("FTE") that are vastly deflated and therefore not the full costs based on the Commission-approved method. Ms. Gregor's estimates are based on numbers that are *below* FDC. The Companies provided the estimates for 2005-2007[5]. The Companies provided estimated values for the factors underlying the estimated costs only for years 2005 and 2006. An example casts doubt on the validity of all the Companies' cost estimates. The estimated values include the duration of the solicitation call of 0.17

[5] Initially the Companies maintained that the costs were based on direct time reporting. Later, they determined that these costs were based on an estimated allocation percentage.

minutes (or 10 seconds). PGL DAS 1204 Attach 01, pp. 1 and 4; Staff Cross Ex. 14, pp.2 and 5. However, when the Companies' witness, Ms. Gregor read the script at the hearing, it took her 30 seconds just to read the script, which is three times the Companies' 10 second estimate. Tr., September 2, 2011, p. 897. Additionally, these 30 seconds do not include any allowance for those customers who would ask questions. Thus, the basis for the estimates is not reliable. These estimates may be off by more than a factor of three. Since the Companies were required under the STA to provide services at FDC but have clearly discounted them, the Commission should choose another basis for the correct allocation of customer relations costs.

Eighth, there is evidence that the Companies provided other services for which they did not charge PEHS. In 2005, 2006 and 2007 there was an estimate of FTEs for these other services which include sales and marketing, materials production, market development, and market research. In 2006 there was an estimate of more than $143,000 (before overhead) for these other services which include executive office, market development, graphics and corporate research. PEHS never paid for these services in 2006. The only amount paid to the Companies by PEHS was for customer relations – Staff Ex. 9.0, Attachment D, Companies revised corrected responses to Staff DR DAS 2.10, a category that includes solicitation but precludes these other services. Tr, September 2, 2011, pp. 913-915. There is also no evidence that these services are not currently being provided for PEHS by IBS at no charge. If there are other services, as indicated above, that the Companies did not originally disclose that have not been reflected in the test year, then the adjustments proposed by the Companies will be even further from the proposed amount.

The Companies have created a contradictory argument on the subject of solicitation expenses and services for PEHS through various responses to discovery and multiple rounds of testimony; stating one thing on direct, another on rebuttal, and then asserting that they were wrong in rebuttal testimony and actually had it right the first time. The Companies witness and evidence is not credible in these matters. They have not provided a basis for the FDC costs that are required by the agreement. In absence of any credible evidence that these levels are cost are accurate, Staff recommends that the ratepayers receive a credit for the market value of the solicitation services performed by IBS on behalf of PEHS.

The Commission should draw four conclusions from this evidence: (1) there is no evidence of any credit in the original test year expenses for customers relations services provided by IBS for PEHS; (2) the estimates provided by the Companies are not the full costs of providing these services as required under the governing agreement; (3) since there is no established estimate of FDC, another adjustment should be used; and (4) the adjustment should be based on the market value of these services. The Commission should utilize the estimate of this market value provided by Staff Witness Sackett, which is based on the margin of $656,267 and $116,361 that PEHS makes on PPP for Peoples Gas and North Shore respectively. Staff Ex. 18.0, p. 23. This margin was never refuted by the Companies. Only Staff's proposal ensures that ratepayers receive the full benefit for all value of these services to PEHS.

In the alternative, if the Commission determines that Staff's proposed amount is not warranted, Staff recommends that the Companies rebuttal testimony adjustment for

$70,000 is more appropriate than their surrebuttal testimony recommendation of no adjustment.

7. Depreciation

a. Depreciation Expense on Forecasted Additions

The argument for Depreciation Expense on Forecasted Additions is contained in Section C.1. A.(i).

b. Derivative Adjustments from Contested Adjustments

Staff's position is that once a decision is made on the contested adjustments any derivative adjustments fall out of the formulae. Staff is not aware of any dispute over those formulae used to make the derivative adjustments.

8. Revenues

a. Repair Revenues

Repair Service is another area where the Companies freely admit that they have been operating with their affiliate in violation of the STA. The STA requires that the Companies charge their affiliates the "pricing mechanism approved by the Commission" or, if none exists, the fully distributed cost ("FDC") of providing that service. Attachment F, p. 6. However, the Companies admit that for the years 2008-2010 they have not charged PEHS for the loadings above explicit costs as required. NS-PGL Ex. 38.0, p. 10. Since the Companies admit that they have not charged the FCD of providing that service, the Commission should approve an alternate "pricing mechanism" where the affiliate must pay the ratepayer rate.

Furthermore, the Companies acknowledge in surrebuttal testimony that they neglected to include any repair revenues in the test year. NS-PGL Ex. 38.0, p. 10. They also acknowledge that they forgot to include any of these revenues in the test year for the previous rate case, Staff Cross Exhibit 15, pp. 14 and 20, and that an adjustment is needed to the test year to include these revenues. However, the amount of the proposed adjustment is based on historical amounts they charged PEHS which were not at FDC. NS-PGL Ex. 38.0, p. 10. This proposed adjustment provides further evidence that Commission oversight on these agreements is needed to ensure proper Company compliance.

The amount of the adjustment should not be based on the historical amount charged plus loadings for the following reasons. First, the Companies charge their ratepayers for the same types of repairs. According to the Companies' witness Ms. Gregor, these charges are based on the average rate of those repairs plus a margin. Staff Ex. 18.0, Attachment I; Companies responses to Staff DR DAS 6.08; Attachment H - Companies responses to Staff DR DAS 9.08. However, the average of the charges to PEHS are roughly half of the average of what the ratepayers are charged for the same service. The Companies cannot find any study that shows how these rates were determined nor has it provided any basis to support this profit margin of 70% for Peoples Gas[6] and 115% for North Shore[7]. Staff Ex. 18.0, Attachment H; Companies response to Staff DR DAS 9.08. The amount of these margins, which the Companies allege explain the difference in repair charges, would be insufficient to bridge the gap

[6] The difference between the unrefuted average of Peoples Gas non-PPP repairs ($60.06) and the unrefuted average of Peoples Gas PPP repairs ($35.57) divided by the the unrefuted average of Peoples Gas PPP repairs ($35.57). (Staff Ex. 9.0, p. 38)

[7] The difference between the unrefuted average of North Shore non-PPP repairs ($60.36) and the unrefuted average of North Shore PPP repairs ($28.04) divided by the the unrefuted average of North Shore PPP repairs ($28.04). (Staff Ex. 9.0, p. 38)

between the rates paid by ratepayers and the charges to PEHS for the exact same services. So the margin would have to be 70% and115% for this to be accurate. If the profit margin is less than this, then the amount charged to PEHS must be discounted in some manner.

There is no reason to conclude that providing repairs for ratepayers takes more time than it does to provide the repairs for PPP customers. The time records on which the charges are based, and which the Companies have provided, cannot reflect the full time spent on providing these services to PEHS.

Last, the affiliate uses the ratepayer rate as the price to compare in its script where potential customers are told that the repairs apart from the PPP would cost them $70, Staff Ex. 9.0, Attachment D: Companies response to Staff DR DAS 2.09, which is the Companies rate to customers for repairs of exposed piping. Staff Ex. 9.0, Attachment K; Companies response to Staff DR DAS 2.14.

The Companies should be ordered to charge PEHS the same rate that they charge ratepayers. The full amount of these repairs should be included in the test year for Peoples Gas and North Shore respectively. Staff witness Sackett estimated the revenues that each Company should receive if those equal rates are charged. His proposal in his direct and rebuttal testimony was based on an assumption that the Companies had included the average amount in the test year., Since the Companies have acknowledged in surrebuttal testimony that they failed to include *any* repair revenues in the test year – NS-PGL Ex. 38.0, p. 10, the amount of the inclusion should be the full amount of those charges of $17,313 for Peoples Gas and $2,456 for North Shore instead of the difference between them and the test year amounts.

b. Other Issues Relating to PEHS and PEPP, Including Staff Request for Investigation

The Companies have agreed to adjust the revenues in the test year to reflect a higher cost to provide billing services to their affiliate PEHS. This adjustment should be approved to correct a discrepancy and subsidy from ratepayers to PEHS. The Companies have charged PEHS $0.40 per bill or letter from 2004 to 2011. The Companies admit that they cannot provide the basis of this charge. Staff Ex. 18.0, Attachment J; Companies response to Intervenor DR IGS 4.03. Additionally, the Companies did a study in 2011 that revealed that the FDC of providing this service was now $0.54, an increase of 35% since 2004. Staff Ex. 18.0, Attachment J: Companies responses to Intervenor DR IGS 4.03. The charge did not change through two rate cases; the test year for each rate cases reflected only the revenues at $ 0.40. Staff Cross Ex. 15, pp. 15-16 and 21-22; Companies responses to Staff DR DAS 13.05. The Companies agreed to include the full amount of $0.54 per bill in their surrebuttal testimony. NS-PGL Ex. 38.0 p. 11.

Staff witness Sackett recommended that the Commission order an investigation into the Companies dealings with their affiliates and the support for PPP in general. The preceding discussion in sections V.C.6 and V.C.8 amply demonstrates at a minimum a lack of attention by the Companies to proper interaction between themselves and their affiliates and at a maximum complete abuse of the law and Commission orders. The proposed investigation is necessary to prevent ratepayers from continuing to subsidize the affiliates. Additionally, there is substantial evidence that the PPP product is over-priced and that customers do not receive the benefit that they perceive. The investigation should also require that the Companies provide full cost justification for the repair rates charged to ratepayers. Given all of the above, a thorough investigation is required to establish that the interactions between the utilities and their affiliates are in the public interest, the standard for such interactions.

c. Warranty Products (Revenue and Non Revenue)

D. Taxes Other Than Income Taxes (Payroll and Invested Capital Taxes) (Uncontested Except for Derivative Adjustments from Contested Adjustments)

E. Income Taxes (Including Interest Synchronization) (Uncontested Except for Derivative Adjustments from Contested Adjustments)

F. Gross Revenue Conversion Factor

1. Uncollectible Rate

Staff recommends that the Commission establish uncollectible expense percentages of 0.5936% for North Shore Gas and 2.7927% for Peoples Gas. Staff Ex. 1.0, p. 23. The calculation of the specific rates is shown in footnote 4 of Staff Ex. 1.0, p. 23. The argument for these rates is included in the "Use of Net Write-Off Method" under Section V.C. Contested Issues, # 5- Uncollectibles Expenses and Section VIII.A., Riders UEA and UEA-GC.

2. Derivative Adjustments from Contested Adjustments

VI. RATE OF RETURN

A. Overview

B. Capital Structure

1. Peoples Gas

[Peoples Gas and North Shore are discussed together.]

a. Introduction

The Companies' proposed capital structure is fatally flawed because it reflects the increased risk of its affiliated parent corporation, Integrys Energy Group, Inc. ("Integrys"), in violation of Section 9-230 of the PUA. In addition, the Companies' proposed imputed capital structure is unreasonable because it would result in a lower degree of financial risk than its peers in the gas distribution industry, which causes the Companies' overall cost of capital to be unnecessarily expensive. The Companies' fundamental problem is that its proposed capital structure contains an excessive amount of equity capital. Staff's proposed capital structure, on the other hand, addresses the increased risk due to the Companies' affiliation with Integrys in a reasonable manner that comports with controlling case law and the PUA.

The Companies proposed capital structures contain 56% equity and 44% long-term debt. PGL Ex. 2.1 and NS Ex. 2.1. On the other hand, Staff proposed a capital structure for Peoples Gas that contains 49% equity, 2.6% short-term debt and 48.4% long-term debt and for North Shore a capital structure that contains 50% equity, 3.9% short-term debt and 46.1% long-term debt. *See* Staff Ex. Ex. 13.0C, pp. 7-8. It is important to note that neither the Companies' nor Staff's proposals use the "actual" capital structure nor the forecasted capital structure, for that matter. Rather, the

Companies impute a capital structure that is allegedly similar to the Companies' historical capital structures. PG Ex. 2.0, pp.6-7 and NS Ex. 2.0, pp. 6-7. In contrast, Staff's imputed capital structure correct the fatal flaws in the Companies' proposed capital structure. Either way, both use an imputed capital structure because neither uses the actual or forecasted capital structures.

b. Integrys Has More Financial Risk Than The Companies

Staff witness Ms. Kight-Garlisch pointed out that the Companies' parent, Integrys, carries more financial risk than the Companies themselves. See Staff Ex. 4.0, at 5-9. Ms. Kight-Garlisch provided the following table that clearly demonstrates this fact.

Table 1[8]

		FFO/ Debt[9]	Debt/ EBITDA[10]	Debt/ Capital[11]	Implied Financial Risk[12]
Companies' Proposed Capital Structure				44%	
North Shore	2010	28.25%	2.88X	44.91%	Intermediate
	3-Year Avg.	26.68%	3.61X	44.41%	Significant
Peoples Gas	2010	34.52%	3.02X	43.14%	Intermediate

8 Cells with values that indicate Peoples Gas or North Shore are slightly riskier than the Gas Group are shaded. Cells that are not shaded indicate that Peoples Gas and North Shore Gas have less risk than both Integrys and the Gas Group.

9 Higher values indicate lower risk.

10 Lower values indicate lower risk.

11 Lower values indicate lower risk. Goodwill is **not** subtracted from capital. See Staff Ex. 13.0C, Schedule 13.4.

12 In order of increasing risk, the Standard & Poor's Financial Risk categories are: minimal, modest, intermediate, significant, aggressive, and highly leveraged.

	3-Year Avg.	31.06%	3.78X	46.44%	Significant
Integrys	2010	25.67%	3.40X	47.77%	Significant
	3-Year Avg.	26.44%	5.15X	48.34%	Aggressive/ Significant
Gas Group	2010	28.96%	3.08X	49.24%	Significant
	3-Year Avg.	24.70%	3.28X	50.35%	Significant

Staff Ex. 4.0, at 5; Staff Ex. 13.0C, Schedule 13.4.

Ms. Kight-Garlisch explained that Standard & Poor's has rated the business risk profiles of both the Companies and the Gas Group as "Excellent." Whereas, Integrys has greater operating risk that is reflected in Standard & Poor's "Strong" business risk profile rating. The S&P matrix implies a credit rating of A/A- for the Companies, A- for the Gas Group, and A-/BBB+ for Integrys. As can be seen in the table above, the Companies have better (*i.e.*, indicative of higher financial strength) cash flow ratios and much lower debt ratios than Integrys and similar if not better cash flow ratios and lower debt ratios than the Gas Group. Id., at 6.

Thus, Ms. Kight-Garlisch testified that the effect of the Companies' affiliations with unregulated or non-utility companies on their costs of capital is evident in their current credit ratings. Moody's, which emphasizes the stand-alone strength of Integrys' subsidiaries, has given the Companies an issuer credit rating of A3. In comparison, the BBB+ issuer credit rating Standard & Poor's has given the Companies reflects the consolidated credit profile of Integrys. That is, the Standard & Poor's credit ratings of the Companies reflect the business and financial risk of Integrys rather than the standalone business and financial risk of the Companies. The ratios presented in Table 1 indicate that the Companies have less financial risk than Integrys. The Companies' financial risk and business risk together imply a standalone S&P issuer credit rating of A/A-. Yet, the

Companies actual S&P credit ratings match the BBB+ of their parent, Integrys. All else equal, a company with less business risk can carry a lower percentage of equity on its balance sheet than a company with greater business risk. Nevertheless, the Companies' equity ratios of around 55% are higher than their riskier parent company's common equity ratio of about 52%. See Staff Ex. 13.0C, Sched. 13.4. Both the Companies' credit ratings and financial ratios indicate that their affiliation with unregulated or non-utility companies has increased their risk. Staff Ex. 4.0, at 8.

If this imbalance of risk between the regulated utilities and Integrys is not adequately addressed in the capital structure, ratepayers will pay for the increased risk of Integrys, when only Integrys shareholders should be carrying the costs of this risk. Due to this imbalance of risk and the prohibition in Section 9-230, Staff imputed a capital structure for the Companies. Moreover, the unreasonableness of the Companies' proposed capital structure as demonstrated in the financial risk inherent in the Gas Group (addressed below) also supports Staff's recommendation for an imputed capital Structure.

c. The Companies' Proposed Capital Structure Violates Section 9-230

Section 9-230 of the PUA precludes *any* increased risk of cost of capital caused by an affiliation from being passed on to rate payers. This section employs clear mandatory language removing all discretion from the Commission on this issue. Section 9-230 provides that:

> In determining a reasonable rate of return upon investment for any public utility in any proceeding to establish rates or charges, the Commission *shall not* include *any* (i) incremental risk, (ii) increased cost of capital, or (iii) after May 31, 2003, revenue or expense attributed to telephone

> directory operations, which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies.
>
> 220 ILCS 5/9-230 (emphasis added).
>
> Moreover, Illinois courts interpreted Section 9-230 to mean that:
>
> We hold that if a utility's exposure to risk is one iota greater, or it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, the Commission must take steps to ensure that such increases do not enter in its ROR calculation.
>
> *Illinois Bell Tel. Co. v. Illinois Commerce Comm'n*, 283 Ill. App. 3d 188, 207 (2nd Dist. 1996)("*IBT*").

Under the clear mandatory directive of Section 9-230 and the equally clear directive of controlling case law, the Commission cannot adopt a capital structure that reflects the increased risk of Integrys.

The fundamental flaw in the Companies' proposed capital structure is that it contains an excessive amount of equity capital (56% for both PGL and NS). As the Illinois courts have explained, "equity is a more expensive form of capital than debt." *IBT*, 283 Ill. App. 3d at 204. Consequently, the "more equity in a utility's capital structure, the higher the ROR must be to recover the cost of capital." *Id*. *See also Citizens Utility Board v. Illinois Commerce Comm'n*, 276 Ill. App. 3d 730, 744 (First Dist. 1995)("*CUB*")("[S]ince equity always costs more than debt, as a corporation increases its proportion of equity, its total cost of capital generally increases, although the cost of debt and the cost of equity both decrease.").

Moreover, the Companies are incented to use a capital structure with an excessive amount of equity, which would then allow Integrys a greater return on its capital, while leaving ratepayers to shoulder the costs. The court in CUB succinctly explained that:

> When a larger corporation owns a utility, the corporation is generally motivated not to establish an optimal, lowest cost capital structure for the utility, but to use instead a structure with a greater percentage of equity than is optimal, thereby allowing the corporation to realize a greater return. The assured profits from the regulated utility can then bolster the security of the corporation, allowing it to sell its own debt instruments at lower cost and use the debt capital to finance riskier, unregulated and competitive ventures. Thus, the corporation maintains an overall capital structure with a higher proportion of low-cost debt, while reporting the capital structure of the owned utility with a higher proportion of high-cost equity.

CUB, 276 Ill. App. 3d at 745.

The Companies' proposed capital structure clearly reflects these incentives (harmful to the ratepayer but beneficial to Integrys shareholders). Staff's proposal does not.

d. Staff's Proposed Capital Structure Is Reasonable

In addition to violating section 9-230, the Companies' imputed capital structure is unreasonable. The Companies proposed capital structure indicated less financial risk than the Gas Group. Financial theory posits that investors require higher returns to accept greater exposure to risk. Conversely, the investor-required rate of return is lower for investments with less exposure to risk. Thus, the cost of common equity estimated for the Gas Group would exceed the costs of common equity for North Shore and Peoples Gas unless the financial risk of the Companies is brought in line with that of the Gas Group. Staff Ex. 13.0, at 6-7.

Ms. Kight-Garlisch explained that the S&P financial risk ratios based on Staff's proposed revenue requirement, capital components and costs in this proceeding clearly show that it is necessary to impute capital structures for the Companies to ensure that their rates of return are reasonable. Table 2 (Table 1 in Staff Ex. 13.0C, at 6) below shows the financial risk ratios and the implied financial risk of each ratio for 2012 based on Staff's proposed revenue requirement for North Shore and Peoples Gas at 50% (Gas Group average equity ratio) and 56% equity (Companies' proposed imputed equity ratio). The calculation of the ratios is presented in Staff Ex. 13.0C, Schedule 13.5.

Table 2

Equity Ratio	FFO/Debt		Debt/EBITDA		Debt/Capital	
2012	Ratio	Implied Risk*	Ratio	Implied Risk*	Ratio	Implied Risk*
North Shore-50% (Gas Group)	28.1%	S	3.2X	S	50%	S/A
North Shore-56% (Companies' Proposal)	33.2%	I	2.7X	I	44%	I
Peoples Gas- 50% (Gas Group)	31.1%	I	3.1X	S	50%	S/A
Peoples Gas- 56% (Companies' Proposal)	36.5%	I	2.6X	I	44%	I
* I=Intermediate, S= Significant and A= Aggressive						

The implied financial risk was determined using the S&P business and financial risk matrix. See Staff Ex. 13.0C, Attachment A. The Companies' proposed imputed capital structure would result in a relatively low degree of financial risk for a gas distribution utility. In comparison, the average capital structure of the Gas Group (including goodwill) is not nearly so conservative. The mean equity ratio for the Gas Group is 50.4% (including short-term debt but with no adjustment for goodwill), with a standard deviation ("σ") of 4.8%. Further, the Gas Groups' other two financial risk ratios are also weaker than the Companies. Thus, the Gas Group's financial risk ratios indicate that its risk is higher than that of North Shore and Peoples Gas. Staff Ex. 13.0, at 6-7. The Gas Group's cost of common equity is a fair rate of return on common equity for the Companies only if the Gas Group's and the Companies' total risk (business risk + financial risk) are similar. Given the Gas Group's greater financial risk, its cost of common equity would exceed that for a company with a similar degree of business risk but with the lower financial risk implied in the Companies proposed imputed capital structures. Stated differently, if the Gas Group's average capital structure were equal to the Companies' proposed capital structures, the Gas Group's average cost of common equity would be lower than the 8.85% value Mr. McNally estimated. Staff Ex. 4.0, at 8. In Staff's judgment, given the difference between the implied forward-looking financial risk for the Companies and the average financial risk of the Gas Group, it is necessary to impute a capital structure for the Companies. Staff Ex. 13.0, at 6-7.

e. Proposed Capital Structures

Staff recommends that the Commission adopt the following capital structures for North Shore and Peoples Gas. For North Shore, the ratio analysis presented in Table 2 (Table 1 in Staff Ex. 13.0) indicates that a capital structure containing 50% equity results in financial ratios that are consistent with the ratios for the Gas Group. Therefore, Staff recommends an imputed capital structure for North Shore that contains 50% equity. To calculate North Shore's respective long-term debt ratio, Staff subtracted North Shore's respective forecasted average 2012 short-term debt ratio of 3.9% from the imputed 50% (100% - 50% common equity ratio) total debt ratio. Thus, long-term debt composes the remaining 46.1% (50% - 3.9%) non-common equity capital in the imputed capital structure. The resulting imputed capital structure for North Shore is 3.9% short-term debt, 46.1% long-term debt and 50.0% common equity. Id., at 7-8.

For Peoples Gas, the ratio analysis in Table 2 (Table 1 in Staff Ex. 13.0) demonstrates that it can support a greater amount of total debt in its capital structure than the Gas Group. Increasing the amount of total debt in Peoples Gas' capital structure from the 50% to 51%, as shown below in Table 3 (Table 2 in Staff Ex. 13.0), results in financial ratios that reflect a "Significant" amount of financial risk, which is consistent with the Gas Group.

Table 3

	FFO/Debt		Debt/EBITDA		Debt/Capital	
2012	Ratio	Implied Risk*	Ratio	Implied Risk*	Ratio	Implied Risk*
Peoples Gas- 49% Equity	30.5%	I	3.2X	S	51%	A
* I=Intermediate, S= Significant and A= Aggressive						

Consequently, Staff recommends a capital structure that contains 49% equity for Peoples Gas. To calculate Peoples Gas' respective long-term debt ratio, Staff subtracted Peoples Gas' respective forecasted average 2012 short-term debt ratio of 2.6% from the imputed 51% (100% - 49% common equity ratio) total debt ratio. Thus, long-term debt composes the remaining 48.4% (51% - 2.6%) non-common equity capital in the imputed capital structure. The resulting imputed capital structure for Peoples Gas is 2.6% short-term debt, 48.4% long-term debt and 49.0% common equity.

f. Short Term Debt

Staff's proposed imputed capital structure contains both short-term debt and long-term debt. The Companies' proposal contains no short-term debt. Staff's proposed imputed capital structure contains short term debt of 2.6% for PGL and 3.9% for NS.

The Companies argue that short-term debt should not be included in the Companies capital structure. NS-PGL Ex. 18.0, pp. 11-12. Staff disagrees.

Ms. Kight-Garlisch explained that due to the fungible nature (i.e., perfect substitutability) of capital, one cannot identify which capital sources fund which assets. Staff Ex. 13.0, at 2. The Commission, accordingly, has concluded that all assets, including assets in rate base, are assumed to be financed in proportion to total capital. *See CIPS/UEC Proposed general increase in rates, Order*, Docket Nos. 02-0798, 03-008 and 03-0009 (Cons.) (October 22, 2003), p. 67. *Id*. Since the Companies rely on short-term debt as a source of funds (Staff Ex. 13.0C, at 2), short-term debt should be included in their capital structures unless it is shown that short-term debt does not support rate base. The Companies have not shown that short-term debt does not support rate base. To the contrary, the Companies have stated that they fund the difference between rate base and "permanent capital" with short-term debt. NS-PGL Ex. 35.1N and 35.1P.

2. North Shore

See Section VI(B)(1) above.

C. Cost of Long-Term Debt

[Peoples Gas and North Shore are discussed together.]

1. Peoples Gas

The Companies and Staff agree that the embedded cost of long-term debt for North Shore is 5.51%. Staff Ex. 4.0, Schedule 4.3N and NS-PGL Exhibit 18.1N. The Companies and Staff do not disagree with the two alternative calculations of the embedded cost of long-term debt for Peoples Gas depending on whether or not debt

Series PP is included in that calculation. Staff Cross Ex. 2. Specifically both Staff and the Companies agree that the embedded cost of long-term debt for Peoples Gas is 4.24% including Series PP and 4.62% excluding Series PP. The only remaining issue is whether or not Series PP should be removed from the 2012 forecasted amount of long-term debt for Peoples Gas balance of long-term debt. Staff Ex. 13.0, at 2 and NS-PGL Ex. 35.0, pp. 8-9.

Although the Companies witness Ms. Gast points out that Peoples Gas has filed a petition requesting Commission approval (NS-PGL Ex. 18.0, p. 13), the mere filing of a petition does not guarantee that the Commission will grant approval of the requested transaction. Ms. Kight-Garlisch explained that Series PP should only be removed if the Commission enters an Order in Docket No. 11-0476 approving the purchase of the tax-exempt securities backed by Series PP. In fact, in Docket No. 11-0467, the Commission issued an Interim Order directing "Peoples Gas to file an appropriate petition seeking Commission approval of the purchase and resale of IDFA bonds under Section 7-102 the Act." Interim Order, ICC Docket No. 11-0269 (May 4, 2011), at 4.

Since the Commission has not entered a final order in Docket No. 11-0476, Staff continues to recommend that Series PP remain in Peoples Gas' average 2012 balance and cost of long-term debt. Staff Ex. 13.0, at 3.

2. North Shore

See Section VI(C)(1) above.

D. Cost of Short-Term Debt

[Peoples Gas and North Shore are discussed together.]

1. Peoples Gas

Staff addressed the cost of short term debt for the Companies together. Staff Ex. 4.0, at 14-15. The cost of short-term debt is 4.04% for North Shore and 2.62% for Peoples Gas. Id. North Shore's short-term debt is in the form of inter-utility loans from Peoples Gas and Peoples Energy Corporation ("PEC"), which rate is based on comparable commercial paper rates. *Id*. Peoples Gas' short-term debt consists of commercial paper and inter-utility loans from North Shore and PEC; the rate on both is the commercial paper rate at the time of borrowing. To estimate North Shore's and Peoples Gas' cost of short-term debt, Staff first converted the May 12, 2011, 0.10% discount rate on 30-day, commercial paper into an annual yield of 0.101% using the following formula: *Id*.

$$\text{Annual yield} = \left(\frac{\text{discount rate} \times \left(\frac{\text{days to maturity}}{360} \right)}{1 - \text{discount rate} \times \left(\frac{\text{days to maturity}}{360} \right)} \right) \times \left(\frac{365}{\text{days to maturity}} \right)$$

Staff then added the annual percentage cost of bank commitment fees to the annual commercial paper yield. For North Shore, Staff determined that approximately $268,208 in annual fees should be included in the cost of short-term debt. *Id*. Staff divided that amount by the average balance of short-term debt outstanding, $6,812,292, to derive the 394 basis point increase to Staff's estimate of North Shore's cost of short-term debt of 4.04% (0.10% + 3.94% = 4.04%). *Id*. For Peoples Gas, Staff determined that approximately $917,290 in fees should be included in the cost of short-term debt. Staff divided that amount by the average balance of short-term debt outstanding,

$36,450,292, to derive the 252 basis point increase to Staff's estimate of Peoples Gas' cost of short-term debt of 2.62% (0.10% + 2.52% = 2.62%). Id.

2. North Shore

See Section VI(D)(1) above.

E. Cost of Common Equity

Three parties presented analyses of the Companies' costs of common equity: the Companies, GCI, and Staff. The Companies initially estimated North Shore's and Peoples Gas's return on equity ("ROE") to be 11.25%, but subsequently updated their estimate to 10.85%. NS-PGL Ex. 19.0 REV, p. 7. GCI estimates North Shore's and Peoples Gas's ROE to be in a range 7.22% to 9.16%. GCI Ex. 5.0, pp. 33-34. Staff estimated North Shore's and Peoples Gas's ROE to be 8.75%. Staff Ex. 5.0 Corrected, pp. 18-19. Staff further recommended a rate of return on the common equity factor for Rider ICR of 6.92%, which represents a 183 basis point adjustment from the base cost of equity. Staff Ex. 5.0 Corrected, pp. 20-21.

1. Peoples Gas

a. Staff's Analysis

Staff witness Michael McNally estimated Peoples Gas's and North Shore's investor-required rate of return on common equity to be 8.75%. Staff Ex. 5.0 Corrected, pp. 18-19. Mr. McNally measured the investor-required rate of return on common equity with discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses. Mr. McNally applied those models to a sample of eight natural gas utility companies ("Gas Group"). The Gas Group was the same sample used by Company witness Moul. To select that sample, Mr. Moul started with the universe of gas utilities contained in the basic service of Value Line, which consists of 12 companies. He then eliminated three companies due to the locational and operational differences, as well as diversification of those companies. He eliminated one additional company because it was the target of an acquisition. The eight remaining companies, AGL Resources, Atmos Energy, Laclede Group, New Jersey Resources, Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, and WGL Holdings, compose the Gas Group. NS Ex. 3.0, p. 3; PGL Ex. 3.0, p. 3.

i. DCF Analysis

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. The companies in Mr. McNally's Gas Group pay dividends quarterly. Therefore, Mr. McNally applied a quarterly DCF model. Staff Ex. 5.0 Corrected, pp. 3-4.

DCF methodology requires a growth rate that reflects the expectations of investors. Mr. McNally used a constant growth DCF model in which he measured the market-consensus expected growth rates with 3-5 year growth rate forecasts published by Zacks. The growth rate estimates were combined with the closing stock prices and dividend data as of May 12, 2011. Based on this growth, stock price, and dividend data, Mr. McNally's DCF estimate of the cost of common equity was 8.50% for the Gas Group. Staff Ex. 5.0 Corrected, pp. 4-6.

ii. Risk Premium Analysis

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Mr. McNally used a one-factor risk premium model, the Capital Asset Pricing Model, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification. Staff Ex. 5.0 Corrected, pp. 7-8.

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Mr. McNally combined adjusted betas from Value Line, Zacks, and a regression analysis. The Gas Group's average Value Line, Zacks, and regression beta estimates were 0.65, 0.53, and 0.49, respectively. The Value Line regression employs 259 weekly observations of stock return data regressed against the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ sixty monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. Since the Zacks beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Mr. McNally averaged the Zacks and regression results to avoid over-weighting monthly return betas. He then averaged that result with the Value Line beta, which produced a beta for the Gas Group of 0.58. Staff Ex. 5.0 Corrected, pp. 13-17. For the risk-free rate parameter, Mr. McNally considered the

0.01% yield on four-week U.S. Treasury bills and the 4.42% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of May 12, 2011. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.5% and 5.1%. Thus, Mr. McNally concluded that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate. Staff Ex. 5.0 Corrected, pp. 8-12. Finally, for the expected rate of return on the market parameter, Mr. McNally conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 12.67%. Staff Ex. 5.0 Corrected, pp. 12-13. Inputting those three parameters into the CAPM, Mr. McNally calculated a cost of common equity estimate of 9.20% for the Gas Group. Staff Ex. 5.0 Corrected, p. 17.

iii. Recommendation

Based on a simple average of the mean sample estimates from his DCF and risk premium models, Mr. McNally estimated that the cost of common equity for the Gas Group is 9.85%. To estimate the cost of common equity for the Companies, Mr. McNally adjusted the Gas Group’s investor required rate of return downward 10 basis points to reflect the reduction in risk associated with Rider UEA, which was authorized in the Companies’ last rate case with the same 10 basis point adjustment. Thus, Mr. McNally estimated the investor-required rate of return on common equity to be 8.75% for both North Shore and Peoples Gas. Staff Ex. 5.0 Corrected, pp. 18-20.

iv. Rider ICR

Mr. McNally testified that, in comparison to rate base cost recovery, the recovery of the capital costs of projects run through Rider ICR would be more timely. Further, Rider ICR effectively eliminates the risk that prudent and reasonable project costs will not be recovered. Since Rider ICR would improve the timeliness and certainty of cash flows, it would reduce the Companies' risk. Thus, if adopted, a downward adjustment to the cost of common equity factor in Rider ICR would be necessary. Staff Ex. 5.0 Corrected, p. 20.

Specifically, using the same approach he used in the Companies' last rate case, which was adopted by the Commission, Mr. McNally recommended a 183 basis point downward adjustment to the base cost of equity that he recommended for Peoples Gas. That adjustment equals one-half of the spread between the current yield for AAA-rated, 30-year utility bonds (5.10%) and Mr. McNally's base cost of equity recommendation for Peoples Gas (8.75%). Mr. McNally reasoned that if Rider ICR protected the Company against all risk of non-recovery of investments in the ICR program, a return consistent with AAA-rated long-term utility bonds would be warranted; in contrast, if Rider ICR had no effect on Peoples Gas's risk, the base cost of equity recommendation for the Company would be warranted. Mr. McNally explained that while Rider ICR eliminates the risk of non-recovery of prudent and reasonable costs, the prudency and reasonableness of Rider ICR expenditures are still subject to annual reviews. Thus, Mr. McNally recommended the midpoint between the AAA bond yield and the full cost of common equity. Staff Ex. 5.0 Corrected, pp. 20-21.

b. Response to Criticisms of Staff's Analysis

Two different Company witnesses claim that previously authorized returns indicate Staff's return recommendation is understated. NS-PGL 19.0 REV, pp. 2-4; NS-PGL 20.0, pp. 13-14. Generally, such results-based comparisons are of limited value, as the previously authorized returns are based on facts that differ from those in this proceeding and are, thus, likely inapplicable (i.e., they represent authorized returns for *other* companies, in *other* jurisdictions, at *other* times representing *other* market environments). But in this case, the Companies' comparisons are meaningless, as the critical facts needed to assess the degree of comparability are unknown. Specifically, both Company witnesses failed to: (1) identify the relative risk, as exemplified by credit rating or any other metric, of each of the utilities involved in those return decisions; (2) specify whether the allowed ROEs used in the study included adjustments for ROE adders that had no relation to the utility's risk or to interest rates (e.g., flotation expense costs, rate case settlements); (3) specify whether the allowed ROEs studied were market-based; and (4) provide the context regarding the market environment in which those decisions were made (e.g., interest rate level). Without such data, those comparisons are useless.

Mr. Moul suggests that Staff's cost of common equity recommendation does not "make any common sense," given the current market environment. NS-PGL 36.0, p. 3. He is wrong. To begin with, his argument is based on his comparison to previously awarded ROEs, which, as explained above, is of no value for such an assessment. Further, as Mr. McNally pointed out, given the context of the current interest rate environment, with interest rates at the lowest they have been in 20 years, Mr. McNally's cost of common equity estimate is what a rational investor would expect. Staff Ex. 14.0, pp. 38-39. Finally, given the return authorized for the Companies in their last rate case and the approximately 115 basis point reduction both Mr. McNally and Mr. Moul estimated in the Companies' costs of common equity since that case, Mr. McNally's recommendation does "make common sense." Staff Ex. 14.0, pp. 2-3. In fact, given the above facts, it is Mr. Moul's 10.85% recommendation that is clearly inconsistent with the current market environment.

Mr. Moul further claims that Staff's ROE is understated because it fails to recognize the higher risk of the Companies relative to that of the sample companies. NS-PGL Ex. 19.0 REV, pp. 9-10. Once again, he is wrong. Mr. Moul himself analyzed the sample relative to the Companies and made no adjustment to his sample cost of common equity, indicating that any risk differential between the Gas Group and the Companies was insignificant. PGL Ex. 3.0 Rev., pp. 45-46; NS Ex. 3.0 Rev., pp. 45-46; NS-PGL 19.0, p. 8; Tr., August 31, 2011, p. 465. Furthermore, in response to Mr. Moul's criticism, Mr. McNally conducted a more comprehensive qualitative and quantitative analysis and found that, if anything, a downward adjustment would be warranted, as the Companies' total risk levels are the same or slightly *lower* than those of the Gas Group. Staff Ex. 14.0, pp. 33-36. Likewise, two analyses performed by Ms. Kight-Garlisch, based on the S&P risk matrix, both indicated that the Companies are of similar or slightly lower risk than the Gas Group. Staff Ex. 4.0, pp. 5-6; Staff Ex. 13.0C, pp. 4, 6-7. Thus, Staff's ROE is not understated. To the contrary, had Staff made an upward adjustment, it would have resulted in an overstated cost of common equity.

Mr. Moul also claims that Staff's use of the most recent spot data is more arbitrary than the use of a recent historical average. NS-PGL 19.0 REV., pp 11-12. While Staff is glad to see Mr. Moul's apparent acknowledgement that his use of historical averages is arbitrary, his conclusion that use of the most recent spot data is somehow more arbitrary is absurd. Obviously, the use of a historical average requires the selection of both a beginning date and an end date. For a spot rate, the beginning and ending date are one and the same. Clearly, selecting two dates cannot be less arbitrary than selecting one. Regardless, Mr. McNally's analysis was performed using the most recent data available as of that date, the selection of which was dictated by the case schedule, which was, of course, dictated by the initial filing date selected by the Companies. Staff Ex. 14.0, p. 8. Mr. Moul's claim is based on the similarly absurd argument that the use of the most recent spot data is, like the equity risk premium he used in his risk premium model, historical. NS-PGL Ex. 19.0 REV, p. 12. It is not. While the most recent data will, of course, be historical by the time an Order in this proceeding is produced, that is inevitable with <u>any</u> analysis; by Mr. Moul's reasoning, a current cost of common equity is <u>impossible</u> to produce. Regardless, the most recent spot price will always be more timely than a historical average and is, thus, preferable. An analysis using the most current data reflects all information that is available and relevant to the market at the time of that analysis, while analyses using older data reflect information that the market no longer considers relevant, a fact Mr. Moul acknowledges. Therefore, use of a historical average requires the analyst to subjectively determine what data is no longer relevant, needlessly and inappropriately replacing the collective judgment of all investors with his own. Moreover, Mr. Moul's use of historical data includes the added flaw of inappropriately mixing and matching data from different points in time. Staff Ex. 14.0, p. 11. For example, Mr. Moul combines historical stock prices with the most recently published earnings growth estimates. NS-PGL Ex. 19.03, p, 1; NS-PGL Ex. 19.05, p, 1. That combination implies that investors buying and selling stock in January 2011 were basing those investment decisions on growth rates that were not published until June 2011. Staff submits that any analysis that implies such perfect prescience is irredeemable, to put it mildly.

Mr. Moul claims that Staff's analysis is not responsive to changes in volatility and, "for this reason alone, Commission should disregard Staff's cost of equity estimates." NS-PGL Ex. 363.0, pp. 3-5. He again is wrong. To begin with, the Chicago Board Options Exchange Volatility Index ("VIX") measures volatility of the overall stock market, not natural gas utilities alone. Obviously, natural gas utility stock movements are not synchronized with the overall market, as evidenced by the average beta of the Gas Group. Beta, as Mr. Moul explains, "measures the sensitivity of rates of return on a particular security with general market movements." PGL Ex. 3.13F, p. 2; NS Ex. 3.13F, p. 2. Both Mr. Moul and Mr. McNally estimated the Gas Group beta to be significantly below the market beta of 1.0. Thus, one would not expect natural gas utility returns to be particularly sensitive to overall market movements, making the VIX a poor indicator of what investors expect for natural gas utility returns. Indeed, it is precisely in times of high overall volatility that investors redirect their investment dollars to relatively low risk investments, such as utility stocks, in a "flight to safety," which Mr. Moul acknowledges. Staff Ex. 5.0, pp. 35-36; PGL Ex 3.13D, p. 4; NS Ex 3.13D, p. 4. Nevertheless, as Mr. Moul's own testimony demonstrates, Staff's results do fluctuate generally with the VIX.

The table Mr. Moul presents in his surrebuttal testimony reveals that four out of six times, the direction of the change in Staff's overall result from the prior result corresponds to the direction of the change in the VIX from its prior level. Further, like the general trend for the VIX, Staff's overall results were lowest as of the May 12th analysis and highest as of the August 10th update. NS-PGL Ex. 36.0, p. 4. Finally, Mr. Moul's advocacy of historical data would cause his analyses to be even less responsive to changes in market volatility than Staff's analysis, which uses the most recent market data. Thus, his argument would be even more applicable to his own analysis than to Staff's.

Finally, Mr. Moul, in defense of the inconsistencies in his analysis, claims that Staff has been inconsistent, since Mr. McNally presented a constant growth DCF in this proceeding, despite presenting a non-constant growth DCF ("NCDCF") in the Companies' last rate case. NS-PGL Ex. 36.0, p. 5. However, Mr. Moul's criticism itself is astonishingly inconsistent. First, Mr. Moul criticized Staff's use of a spot date analysis because it is the same approach Staff used in the Companies' last rate case (which the Commission accepted at least 3 times in that same Order); then, he criticized Staff's use of the constant growth DCF model because it is not the same approach Staff used in the Companies' last rate case (which the Commission rejected entirely). Thus, Mr. Moul's criticism is not only internally inconsistent, but inconsistent with the Commission findings. His criticism is also inconsistent with his testimony in the Companies' last rate case, in which he criticized Staff's use an NCDCF analysis as "abandoning a long-standing adherence to the constant-growth DCF model." That is, Mr. Moul now criticizes Staff for choosing a DCF model consistent with both his previous criticism and the Commission's long-standing policy. Moreover, <u>his criticism is even inconsistent with his own justifications for the use of a constant growth DCF model, which he himself employed in this proceeding</u>. Indeed, consistency with a Staff approach that was accepted by the Commission was the very basis Mr. Moul states for the implementation of a constant growth DCF model. Yet Mr. Moul now alleges that Staff's use of that previously accepted approach is "inconsistent." Staff Ex. 14.0, pp. 13-15.

Despite all this apparent inconsistency, there is one consistency in Mr. Moul's arguments: the acceptance of each of his arguments would produce a higher RIOE estimate. Therein resides the primary contrast between Mr. Moul's analysis and Staff's analysis: while Mr. Moul's analysis is consistently results-driven, Staff's analysis is consistent in application and approach. Mr. Moul's approach needlessly and inappropriately emphasizes the analyst's potentially biased judgment in place of the collective judgment of investors. In contrast, Staff's consistent approach emphasizes a reliance on investor expectations manifested through unbiased market data. Not coincidentally, Staff's results are much more consistent with current market circumstances. In summary, despite Mr. Moul's claim to the contrary, Staff's approach is consistent with:

- Mr. Moul's criticism of Staff's use of an NCDCF in the Companies' last rate case;
- the Commission's rejection of the NCDCF in the last rate case;
- the Commission's "long-standing adherence to the constant-growth DCF model";
- Mr. Moul's reasoning for selecting a constant growth DCF himself;

- Staff's long-standing approach for selecting a DCF or an NCDCF model;[13]
- the return on common equity authorized by the Commission in the Companies' last rate case, given the decline in gas utility costs of common equity since that previous rate order as evident in both Mr. McNally's and Mr. Moul's analyses in both cases;
- the current low interest rate environment; and
- Mr. Moul's own results when they are corrected for consistency with the Commission's findings in the Companies' last rate case.

c. Companies' Analysis

Company witness Moul estimated the Companies' cost of common equity using DCF, risk premium, and CAPM analyses, which he applied to a sample of eight gas utility companies. Based on his analysis, he initially recommended an 11.25% cost of equity for North Shore and Peoples Gas. NS Ex. 3.0, pp. 2-3; PGL Ex. 3.0, pp. 2-3. He updated his analysis in his rebuttal testimony and, consequently, reduced his recommendation to 10.85%. NS-PGL Ex. 19.0 REV, pp. 6-7. Unfortunately, Mr. Moul's analysis contains several errors that led him to over-estimate the Companies' cost of common equity. The most significant flaws in Mr. Moul's analysis of the Companies' cost of common equity are his (1) inclusion in his recommendation of the results of an inappropriate risk premium model; (2) exclusion of his DCF results from his

[13] Indeed, that Staff's model selection is dictated by current market circumstances is why the model selected can change from one case to another. This is yet another example of Staff recognizing and acknowledging the overall market environment, despite to Mr. Moul's claim to the contrary

recommendation; (3) inappropriate manipulation of his growth rate estimate; (4) inclusion of an unwarranted leverage adjustment in his DCF and CAPM estimates; and (5) inclusion of an unwarranted size premium adjustment in his CAPM estimate. Staff Ex. 5.0 Corrected, p. 22.

i. Risk premium analysis flaws

In determining the equity risk premium, Mr. Moul began with a 6.23% base equity risk premium estimate representing the historical earnings spread between investment grade public utility bonds and the S&P Utilities Index for the periods 1974-2007 and 1979-2007. Mr. Moul adjusted the 6.23% equity risk premium down to 5.50% in recognition of the lower risk of his proxy group in comparison to the S&P Public Utilities Index. He then added the 5.50% equity risk premium to a projected 5.75% long-term, A-rated public utility bond yield estimate, which resulted in a cost of common equity estimate of 11.25%. NS Ex. 3.0 Rev., pp. 30-34; PGL Ex. 3.0 Rev., pp. 30-34.

Mr. Moul's risk premium analysis contains several flaws that undermine the reliability of the resulting estimates. First, Mr. Moul's base equity risk premium estimate is calculated from historical data, which is inappropriate. Use of historical data falsely assumes that market data reverts to a mean, despite the fact that security returns approximate a random walk. Moreover, no true mean exists. Therefore the selection of a measurement period will necessarily be arbitrary, and that arbitrarily selected measurement period will dictate the magnitude of a historical risk premium, as Mr. Moul's testimony demonstrates. For example, had Mr. Moul used the 1966-2007 measurement period, his base equity premium estimate would have been 4.85% rather than 6.23%, which would need to be adjusted downward even farther for the less risky

Gas Group. Thus, while this approach would, at best, only produce the "correct" risk premium by sheer chance, it is unquestionably, and incurably, subject to manipulation. Second, Mr. Moul's measurement periods end in 2007, rendering his estimates outdated even by historical risk premium standards. Third, Mr. Moul added a risk premium measured from an investment grade bond index to an estimate of A-rated bond yield without providing any support that the two are compatible. Specifically, Mr. Moul provides no support that the public utility bond index has been, and remains, composed of A-rated bonds with similar terms to maturity as reflected in his A-rated bond yield estimate. Both term to maturity and credit rating are important determinants of bond returns. Fourth, Mr. Moul provided no quantitative support for the adjustments he made in deriving his estimate of the equity risk premium for the Gas Group (5.50%) from the base equity risk premium (6.23%). Staff Ex. 5.0 Corrected, pp. 23-24.DCF Model.

ii. DFC Model

Mr. Moul claims that the growth prospects for the natural gas industry generally, and the Gas Group in particular, have been "negatively impacted by the recent economic conditions" and that dividend yields for the Gas Group "remain low in response to the low interest rate environment." Thus, he concludes that the DCF produces a "misleading" measure of the cost of common equity for gas utilities. He suggests that conclusion is confirmed by the fact that his DCF result is inconsistent with his risk premium and CAPM results. Therefore, he excluded his DCF result from his cost of common equity recommendation. NS Ex. 3.0, pp. 5-6; PGL Ex. 3.0, pp. 5-6.

Mr. Moul's reasoning is wrong. The low growth rates and low interest rate environment Mr. Moul cites simply indicates that the cost of capital is low. A relatively low cost of capital is not a reasonable rationale for dismissing the results of a model that reflects those low costs. To the contrary, since the Companies' costs of capital are low, their authorized rates of return should be low for cost-based rate setting purposes. Mr. Moul's argument, on the other hand, suggests that the Commission should grant rates based on higher costs of capital than the current economic environment suggests. Mr. Moul has provided nothing to demonstrate that current growth rates and dividend yields are somehow invalid or misstate investors' expectations and requirements. In fact, his argument amounts to nothing more than unsupported speculation. Staff Ex. 5.0 Corrected, p. 25.

Likewise, his claim that his conclusion is supported by the fact that his DCF results are low relative to his risk premium and CAPM results is erroneous. That fallacious reasoning assumes the conclusion as to what the appropriate cost of common equity is. In fact, his "outlier" argument rests on a comparison of his DCF result to results that were inappropriately inflated through techniques that have been repeatedly rejected by the Commission. When those errors are corrected, the results show that his DCF is not understated, but rather, that his risk premium and CAPM analyses are overstated, nullifying his "outlier" argument. Staff Ex. 5.0 Corrected, pp. 25-26.

Curiously, while Mr. Moul excluded the result of his DCF analysis in this proceeding due to the recent economic conditions, he relied upon both a CAPM and a DCF model in the Companies' previous rate case, which was filed at a time when market conditions were much worse. Specifically, the VIX averaged 20.40 from January

1990 through January 2011, peaked at 55.89 in October 2008 and remained at 40.00 for the month in which Mr. Moul performed his analysis for the Companies' last rate case (December 2008). In contrast, the VIX at the time of his analysis in this case (December 2010) was below the 20-year average, at 17.75 – less than half what it was in December 2008. Moreover, the difference between Mr. Moul's CAPM and DCF estimates in the Companies' previous proceeding (1.93%) was greater than it is in this proceeding (1.54%). Yet, now he alleges that the difference renders his DCF results invalid. Staff Ex. 5.0 Corrected, p. 26. His previous acceptance of DCF results when the argument he provides for excluding them in this case would have been much more applicable betrays that argument as disingenuous.

Mr. Moul's decision to abandon his DCF result is even more curious when one considers his argument against Staff's analysis regarding its responsiveness to changes in the VIX. Mr. Moul presents the average result for each of Staff's analyses and the corresponding VIX value and concludes that Staff's analyses are unresponsive to changes in the VIX. NS-PGL Ex. 36.0, p 4. However, when one looks at the DCF and CAPM results for each of Staff's updates independently, it is clear that the DCF is more responsive to the VIX than the CAPM. The table below shows each of the DCF and CAPM results and the corresponding VIX value, along with a plus (+) or minus (-), indicating the direction of the change from the prior value:

Table 1

Date	DCF	CAPM	VIX
5-12-11	8.50%	9.20%	16.03
6-22-11	8.80% (+)	9.22% (+)	18.52 (+)
6-29-11	8.64% (-)	9.29% (+)	17.27 (-)
7-6-11	8.53% (-)	9.39% (+)	16.34 (-)
7-13-11	8.49% (-)	9.31% (-)	19.91 (+)
7-20-11	8.52% (+)	9.35% (+)	19.09 (-)
8-10-11	8.98% (+)	9.05% (+)	42.99 (+)

Staff Ex. 14.0, p. 10. Four out of six times, the direction of the change in the DCF result from the prior result corresponds to the direction of the change in the VIX from its prior level; that is only true of two of the six changes in the CAPM. Further, the VIX was at its lowest as of the May 12th analysis and at its highest as of the August 10th update. Similarly, the DCF result was only one basis point above from its lowest point as of the May 12th analysis and at its highest as of the August 10th update. In contrast, the CAPM was approximately at its midpoint as of the May 12th analysis and moved in the opposite direction of the VIX from there, with its *lowest* point as of the August 10th update. Mr. Moul's models would respond similarly, as they are based on similar inputs. Specifically, the actual and forecasted T-bond yields Mr. Moul used in his CAPM and risk premium model have fallen; his beta does not respond to short-term fluctuations in market volatility, as it is estimated from 5 years of historical data; and his use of historic data to calculate the risk premium input in his CAPM and risk premium model renders those estimates incapable of responding to current market volatility. Yet, although the DCF more closely follows the VIX, the DCF is the only model he threw out from his final recommendation. Thus, Mr. Moul's decision to disregard his DCF result is contrary to his own arguments.

iii. DCF Growth Rates

Mr. Moul relied on IBES, Zacks, and Morningstar earnings per share ("EPS") growth rates in this proceeding. In contrast, in the Companies' last rate case Mr. Moul used earnings growth rates from IBES, Zacks, and Value Line. Although, he maintains that "projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations," he excludes the Value Line estimates in this proceeding and, instead, substitutes the Morningstar estimates without any explanation, much less justification. In fact, the testimony Mr. Moul presents regarding Value Line growth rates is nearly identical to that which he presented in the Companies' last rate case, in which he employed Value Line growth rates, yet his conclusion is directly contradictory. NS Ex. 3.0, p. 21; PGL Ex. 3.0, p. 21.

It was not only unnecessary for Mr. Moul to exclude from his analysis the Value Line EPS growth estimate, which he deemed a reasonable assessment of investor expectations, but it was inappropriate for him to replace that estimate with a growth rate that is an outlier relative to the other growth rate estimates he presents and unsustainably high. Staff Ex. 5.0 Corrected, p. 29. His sample average IBES, Zacks, and Value Line growth rate estimates were tightly clustered within 35 basis points of one another at 4.14%, 4.41%, and 4.06%, respectively, with the highest of those three only 8.6% greater than the lowest. In contrast, at 5.60%,[14] the average Morningstar

[14] Although the sample average Morningstar growth rate did fall to 5.10% in Mr. Moul's rebuttal update, his decision to use Morningstar growth rates was made in his direct testimony based upon the numbers cited above. Nevertheless, even based on his rebuttal update the Morningstar growth rate is still an outlier relative to the IBES, Zacks, and Value Line growth rate (continued…)

EPS growth rate for the sample was 119 basis points (approximately 27%) above the highest of the other three. Thus, it is clearly an outlier relative to other estimates he found reasonable. NS Ex. 3.8, p. 1; PGL Ex. 3.8, p. 1.

In addition, the Morningstar growth rate is unsustainably high. The Morningstar growth rate is approximately 10%-24% greater than the forecasts of overall economic growth, estimated to be between 4.5%-5.1%. No company can sustain a growth rate greater than that of the overall economy, or it would eventually outgrow the entire economy, a mathematical and logical impossibility. Furthermore, even if one assumes overall economic growth will be at the high end of the forecasts (i.e., 5.1%), since utilities are generally below-average growth companies, the sustainability of a growth rate at 5.1%, let alone 5.6%, is dubious for the Gas Group. Moreover, based on the dividend payout and other data published in Value Line for each company in the Gas Group, the ROE implied by the Morningstar growth rates is 14.27% for the sample. The implication that investors expect those companies to sustain a 14.27% rate of return on equity indefinitely is not plausible. Thus, the Morningstar growth rates are not suitable for a constant-growth DCF analysis and his substitution of those growth rates for the Value Line growth rates should not have been made. Staff Ex. 5.0 Corrected, pp. 29-30.

In response, Mr. Moul presented an analysis that he claims demonstrates an average growth rate of 5.95% is sustainable for the Gas Group. NS-PGL Ex. 19.0 REV,

(continued from previous page)

estimates, which were clustered even tighter at that time at 4.33%, 4.31%, and 4.31%. Thus, while the other three sources were within 2 basis points (0.46%) of one another, the Morningstar growth rate was still 77 basis points (approximately 18%) above the *highest* of the other three.

p. 18. However, that analysis is unreliable, as it assumes that all new shares are sold at market price, which for each company in the sample is well above its book value. In reality, most new shares are the result of either stock grants to corporate executives for which the company receives no compensation or stock options, which are not exercised unless the market price is greater than the exercise price. Any new shares issued below market price would produce a lower external growth factor than he estimated, while new shares issued at below book value would actually produce a negative growth rate per share. Mr. Moul failed to take this fact into consideration and, as a result, his estimate of the sustainable growth for the Gas Group is overstated. Staff Ex. 14.0, p. 17.

Even if one ignores all the foregoing arguments and accepts the inappropriate substitution of Morningstar growth rates for Value Line growth rates, Mr. Moul's selection of a 5.0% growth estimate overweights the most extreme of his growth estimates. As noted above, the Morningstar growth estimate is a clear outlier from all the other estimates and unsustainably high. Yet, he effectively assigned that growth estimate a much higher weight by selecting a 5.0% growth rate for use in his analysis. In his direct testimony, the simple average of the IBES (4.14%), Zacks (4.41%), and Morningstar (5.60%) growth rates he employed in his direct testimony is 4.72% for the Gas Group. Yet, to achieve a 5.0% growth rate average from those estimates, one would effectively be giving the Morningstar growth rate 54.34% weight, while only giving the IBES and Zacks growth rates 22.83% weight each. He provides no explanation for his selection of a 5.0% growth rate from those three sources other than his "opinion" that it is "reasonable" for the Gas Group. Staff Ex. 5.0 Corrected, pp. 30-31. This overweighting gets even more extreme with his rebuttal testimony, as he maintained a growth estimate of 5.0%, even though the Morningstar growth rate fell by 50 basis points. NS-PGL Ex. 19.02; NS-PGL Ex. 19.05, p. 1. The simple average of the IBES (4.33%), Zacks (4.31%), and Morningstar (5.10%) growth rates he employed in his rebuttal update is 4.58% for the Gas Group. But in order to obtain a 5.0% growth rate from those estimates, he effectively gave the Morningstar growth rate 87.18% weight, while only giving the IBES and Zacks growth rates 6.41% weight each. Thus, even if one were to erroneously accept Mr. Moul's use of Morningstar growth rates, the more appropriate growth rate to use would be the simple average of all three growth rate sources, or 4.58%. Added to his updated dividend yield of 3.94%, this would produce a DCF cost of common equity estimate of 8.52%, which is nearly identical to Staff's 8.50% DCF estimate.

iv. Leverage Adjustment

Mr. Moul argued that, when a company's book value exceeds its market value, the risk of a company increases if the capital structure is measured with book values of capital rather than market values of capital. Such a notion is absurd. The intrinsic risk level of a given company does not change simply because the manner in which it is measured has changed. Such an assertion is akin to claiming that the ambient temperature changes when the measurement scale is switched from Fahrenheit to Celsius. Mr. Moul's argument confuses the measurement tool with the object to be measured. Specifically, capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. <u>Financial risk arises from contractually required debt service payments;</u> <u>changing capital structure ratios from a market to book value</u>

basis does not affect a company's debt service requirements. Staff Ex. 5.0 Corrected, pp. 31-32.

The Commission rejected the use of leverage adjustments in Docket Nos. 01-0528/01-0628/01-0629 (Cons.), 99-0120/99-0134 (Cons.), and 94-0065. Order, Docket Nos. 01-0528/01-0628/01-0629 (Cons.), March 28, 2002, pp. 12-13; Order, Docket Nos. 99-0120/99-0134 (Cons.), August 25, 1999, p. 54; Order, Docket No. 94-0065, January 9, 1995, pp. 92-93. In fact, the exact same leverage adjustment arguments were rejected by the Commission in the Companies' last two rate cases. Order, Docket Nos. 07-0241/07-0242 (Cons.), February 5, 2008, pp. 95-96; Order, Docket Nos. 09-0166/09-0167 (Cons.), January 21, 2010, pp. 128-129. The Order from the 2007 rate case quite clearly sets forth, in great detail, the reasons such a leverage adjustment should be rejected. For those reasons, that exact same leverage adjustment should be rejected once again in this proceeding.

v. Size Adjustment

Mr. Moul added a risk premium based on firm size to his CAPM analysis. However, Mr. Moul did not provide any evidence to demonstrate that a size premium is warranted for utilities. The study reported in Ibbotson Associates, which forms the basis of Mr. Moul's size-based risk premium adjustment, is not restricted to utilities. Rather, it is based on the entire population of NYSE, AMEX, and NASDAQ-listed securities, which are heavily weighted with industrial stocks. To assume, as Mr. Moul does, that a characteristic drawn from the general (entire market) can be applied to the specific (utilities) is logically fallacious. Thus, the entire basis of Mr. Moul's size-based risk premium is questionable at best. In fact, in direct contrast with Mr. Moul's claims, a study by Annie Wong, reported in the *Journal of the Midwest Finance Association*, specifically found no justification for a size premium for utilities. Staff Ex. 5.0 Corrected, pp. 33-34. In response, Mr. Moul offers nothing more than a one sentence assertion that an article by Thomas Zepp supports a small firm effect in the utility industry. He provides no discussion of the article or explanation for his conclusion whatsoever, in either his rebuttal or surrebuttal testimony. NS-PGL Ex. 19.0 REV., p. 29; NS-PGL Ex. 36.0, p. 8. In contrast, Mr. McNally provided two and a half pages of testimony explaining the numerous, and fatal, flaws in the Zepp study that render its conclusions, indeed its fundamental value in general – let alone its applicability to the Companies – highly dubious. The Zepp "study" was far from a rigorous, scholarly study. In fact it provides no insight into the relationship between small utilities and large utilities and no support for Mr. Moul's size premium adjustment. Staff Ex. 14.0, pp. 26-28. Mr. Moul had no response to Mr. McNally's critique of the article, except to attempt to reverse the argument: the Zepp article was presented in an attempt to refute the Wong article that Staff had previously presented, but Mr. Moul's only response is another single sentence assertion that the Wong article does not refute the Zepp article. NS-PGL Ex. 36.0, p. 8. The Wong article was obviously not intended to refute the Zepp article, since it was published prior to the Zepp article. Instead, the Zepp article was shown to be of no value by Mr. McNally's uncontroverted two and a half page explanation of the glaring weaknesses of that "study."

Even for non-utilities, evidence of the existence of a size-based risk premium is not very strong. Ibbotson Associates data shows that, out of a 1926-2007 study period, small stocks consistently out-performed large stocks only during the 1963-1983 period.

Further, Fernholz found that a statistical property he termed the "crossover effect" was the primary cause of the difference between large and small company stock returns. That is, when a stock in a large stock portfolio experiences a random negative price change that moves it into a smaller stock portfolio, the negative return is assigned to, and therefore reduces, the return on the large stock portfolio. Conversely, when that same stock experiences a random positive price change that moves it back into the large stock portfolio, the positive return is assigned to, and therefore increases, the return on the smaller stock portfolio. Thus, the "small stock effect" may be less a market return phenomenon than a statistical anomaly due to a modeling deficiency. Staff Ex. 5.0 Corrected, pp. 34-35.

A study by Jensen, Johnson, and Mercer found that small stock premiums may be a period-specific phenomenon related to monetary policy. Jensen, et al., observed a size premium during monetary expansions, when the supply of loanable funds increases and investors are more likely to invest in speculative, small company stocks. However, during monetary contractions, as the supply of loanable funds decreases, investors are more likely to switch from speculative investments to safer ones – the well-known "flight to quality" – and no size premium is observed. That investors would consider the smaller firms in the regulated utility sector to be speculative investments is counter-intuitive; and Mr. Moul has not supported that premise. Moreover, since Jensen, et al., did not control their measurement of the small stock premium for risk as measured by beta or other means, the "size premium" they analyzed may already be reflected in the betas of smaller companies, rendering an additional risk adjustment such as Mr. Moul proposes unnecessary. Staff Ex. 5.0 Corrected, pp. 35-36.

Finally, Mr. McNally explained that Mr. Moul's application of the historical size-based risk premiums, as quantified and published by Ibbotson Associates, is inconsistent with the manner in which Ibbotson Associates measured them. While Mr. Moul adds the historical size premium to his CAPM-based risk premium analysis which is based on adjusted Value Line betas, the Ibbotson Associates size-based risk premiums are a function of raw betas. Thus, the "size premium" Mr. Moul adds to his CAPM result is already captured by the adjustment Value Line applies to the betas Mr. Moul used in his CAPM analysis. Any further adjustment is duplicative. Staff Ex. 5.0 Corrected, p. 36.

2. North Shore

See Section VI(E)(1) above.

F. Weighted Average Cost of Capital

1. Peoples Gas

Staff recommends a 6.41% rate of return on Peoples Gas' rate base. Staff Ex. 13.0 Corrected, p. 10, Schedule 13.1.and Staff Cross Ex. 2 (Cos. DR response to SK 8.01) This rate of return incorporates the 4.24% embedded cost of long-term debt, the 2.62% cost of short term debt, the 48.4%, 2.6% and 49.0% capital structure for long term debt, short term debt and common equity, respectively proposed by Staff (ICC Staff Exhibit 13.0 Corrected, Schedule 13.1) and the 8.75% rate of return Staff witness Michael McNally recommends for Peoples Gas's common equity. ICC Staff Exhibit 5.0 Corrected, p. 18.

2. North Shore

Staff recommends a 7.08% rate of return on North Shore's rate base. ICC Staff Exhibit 13.0 Corrected, p. 10, Schedule 13.1. This rate of return incorporates the 5.51% embedded cost of long-term debt, the 4.04% cost of short term debt, the 46.1%, 3.9% and 50.0% capital structure for long term debt, short term debt and common equity, respectively proposed by Staff (ICC Staff Exhibit 13.0 Corrected, Schedule 13.1) and the 8.75% rate of return Staff witness Michael McNally recommends for North Shore's common equity. ICC Staff Exhibit 5.0 Corrected, p. 18.

VII. WEATHER NORMALIZATION (Uncontested)

VIII. RIDERS – NON-TRANSPORTATION

A. Riders UEA and UEA-GC

Staff recommends that, for Riders UEA (Uncollectible Expense Adjustment, applies to classes 1,2,4, and 8) and UEA-GC, the Commission order the Companies to switch from using the uncollectible amount set forth in Account 904 to using net write-offs in each tariff. To be consistent with Section 19-145 (a) of the Act, the Commission would also have to order that net write-offs be used to determine the utility's uncollectible amount in rates.

Currently, Rider UEA bases the uncollectible expense to be recovered through the rider on the balance of Account 904, uncollectibles expense, as stated in the Companies' Form 21 ILCC annual reports to the Illinois Commerce Commission.

The balance of Account 904 fluctuates with changes to the allowance for doubtful accounts. The allowance for doubtful accounts is based on estimates of uncollectible accounts. In determining the account 904 balance, one must consider write-offs of receivables for service related to prior periods and management's projection of revenues that will not be collectible in the next year. Using the net write-off method, however, would ensure that the calculation of incremental uncollectible expenses recoverable through Rider UEA is based on actual accounts written-off and recovered, instead of estimated amounts. Actual information is preferable to estimates since it is more accurate, and should be used whenever available.

The Companies have made reference to stipulations approved by the Commission in Docket Nos. 09-0419 and 09-0420 in arguing against adopting the net write-off method. NS-PGL Ex. 45.0, pp. 26-27. Section 1 of the Stipulation sets forth the amounts of the uncollectible amount included in utility rates through the utility's 2009 rate cases, but does not define the method for determining the amount of the uncollectible expense to include in utility rates in those or Post 2010 Rate Cases[15]. Likewise, Section 2 of the Stipulation does not set forth a method for determining the amount of uncollectible expense to be recovered through riders. Section 2 b states that the amount that will be billed to customers will be based on uncollectible amounts as approved by the Commission. The stipulation does not limit the Commission's discretion in determining the method for computing the appropriate amount of uncollectible expense to be billed to customers. Therefore, using the net write-off

[15] Pursuant to the Stipulation in Docket Nos. 09-0419/0420 (Cons.) (Staff-NS-PGL Joint Ex. 1, Attachment A, par. 1(d)) the current proceedings, i.e. Docket Nos. 11-0280/0281 (cons.) would be the "next rate cases" or the "Post 2010 Rate Cases" for purposes of the Stipulation.

method to determine uncollectible expenses does not conflict with the Stipulation and for the reasons stated above is the preferable method.

The Commission should order the Companies to use net write-off method to determine the uncollectible amount to be recovered in Rider UEA. If the Commission orders the Companies to use the net write-off method in Rider UEA, the Commission, for consistency, should make the same order for the Proposed Rider UEA-GC.

B. Rider VBA

1. Merits of Rider VBA

Staff's position is that Rider VBA is preferable to a straight fixed variable ("SFV") rate design or a rate design that increases the portion of fixed costs that are recovered through fixed customer charges. Staff Ex. 6.0, pp. 3-4. Staff witness Dr. Brightwell testified that from a policy perspective, Rider VBA better aligns with the energy efficiency objectives set forth by the General Assembly because it increases the volumetric charge which promotes conservation. The advantages of Rider VBA include the following: (1) It diminishes the advantage the utility has in choosing when to file a rate case; (2) it reduces the reliance on statistical forecasts for setting rates; (3) it lessens the shifting of costs from high use customers onto low use customers; and finally (4) it reduces the incentive of low use customers to leave the gas system. *Id.*, p. 4.

The energy efficiency objectives set forth in Section 8-104 of the Public Utilities Act are better met through Rider VBA because it increases the percentage of fixed costs that are recovered through volumetric charges. As such, it increases the volumetric rate and reduces the fixed charge. The lower fixed charge increases the total bill savings that are possible through conservation and the higher volumetric charge provides greater bill savings from each therm that is not consumed. *Id.*, p. 5-7. An increase in the volumetric rate of just 3.8 cents per therm could reduce usage by 0.4%, the equivalent of the savings requirement established for Program Year 2 of the energy efficiency program and about a third of the total savings required over the first three years of the energy efficiency program. *Id.*, p. 7.

Dr. Brightwell further testified that Rider VBA diminishes the advantage that the utility has in choosing when to file rate cases. There is an incentive for the utility to file rate cases sooner if revenues fall short of expectations and to delay filing if revenues exceed expectations. Rider VBA stabilizes revenue by providing charges or credits for under or over collection of revenues. Because of these charges or credits, the utility receives income when sales fall short of expectations, which reduces the incentive to file a rate case and the utility must refund any over collections which protects ratepayers from providing excessive returns to the Utilities. *Id*., p. 5.

The charge or credit associated with Rider VBA also reduces the reliance on statistical forecasts for the purpose of setting rates. The very nature of statistical forecasts is such that there is also a margin of error. *Id.*, pp. 4-5. The forecasted number of customers and average use per customer will differ from the actual number of customers and use per customer. Since rates are set on these forecasts, the rates will over collect or under collect. In addition to reconciling for the routine forecast errors that are likely to occur, Rider VBA also diminishes the incentive to manipulate forecasts to the Utilities' advantage. Under an SFV rate or a rate with a higher fixed customer charge, an advantageous forecast sets rates that are far more likely to over collect revenues. This can be accomplished by underestimating the number of customers, the use per customer or both. *Id*., pp. 9-10.

Staff witness Dr. David Brightwell provided additional evidence that the higher fixed charge associated with an SFV rate or a rate with a higher fixed cost than what is being proposed by the Companies also increases the total bills for low use customers and may make it preferable for low use customers to leave the system. To the extent that this occurs, high use customers are worse off in the long run because costs are spread across fewer therms and few customers. This will cause both fixed and volumetric charges to increase for remaining customers. *Id*., pp. 10-11. The evidence presented by Dr. Brightwell showed that the number of non heating customers decreased while the number of heating customers increased in both utilities' service territories. Id, pp. 11-13.

Dr. Brightwell also pointed out that this problem is more relevant to Peoples and North Shore than it is to other utilities in Illinois because the overall costs are higher in the Peoples and North Shore territories. In fact, if the customer charges proposed in this rate case were in effect in 2010, Peoples Gas would have had a higher fixed charge than was found in any of the 150 rate jurisdictions surveyed by the American Gas Association and North Shore Gas' customer charge would have been amongst the highest. *Id*., p. 13. This is relevant because the law of demand states that when all other factors that affect the quantity of gas that consumers buy are held constant, that as price increases the quantity demanded decreases. One would therefore expect greater decreases in the number of customers in the Peoples and North Shore territories than in the Ameren or Nicor territories because the fixed customer charges are significantly higher. Since the loss of customers is likely to be greater in the Peoples and North Shore territories, Rider VBA is preferable to an SFV or a rate that recovers 80% of fixed costs through fixed charges. Staff Ex. 15.0, pp. 7-8.

Perhaps the most significant reason to stabilize revenue through Rider VBA rather than through a rate design that includes a higher fixed charge is that the higher fixed charge shifts more cost recovery onto low use customers and away from higher use customers. Dr. Brightwell estimated that as the customer charge increases, the percentage of customers who will pay more for gas distribution than for the gas being used will increase. Under an SFV rate, Dr. Brightwell estimated that between 20-30% of Peoples S.C. 1 customers and 8-13% of North Shore S.C. 1 customers would pay more for the opportunity to have gas provided than for the actual gas that is provided. These percentages will increase if the fixed charges increase. Staff Ex. 6.0, pp. 14-17.

Rider VBA is clearly preferable to an SFV rate or a rate that increases the percentage of fixed costs recovered through fixed charges. The reconciliation adjusts for over or under recovery by the Utilities. This provides a symmetric risk between ratepayers and shareholders. The VBA also diminishes the reliance on statistical forecasts. This provides advantages to ratepayers because it diminishes the benefits to the Utilities from inaccurate forecasts or from manipulating forecasts for additional revenues beyond what were deemed appropriate in a rate case. The inaccurate forecasts create an asymmetric risk to ratepayers because the utility can file another rate case in the event revenues are too low but ratepayers are unable to file for lower rates when revenues are too high.[16] Finally, Rider VBA better aligns with policies set forth by the General Assembly. The higher volumetric rate associated with higher percentages of fixed costs being recovered through volumetric rates provides greater incentive to conserve gas. The higher percentage of fixed costs that are recovered through volumetric rates also provides lower bills to low use customers many of whom may be amongst the poor and elderly. For all of these reasons Rider VBA is preferable to an SFV rate or a rate with a high percentage of fixed costs being recovered through fixed charges.

2. Tariff Language

Staff recommended edits to the Rider VBA tariff language proposed in the testimony of Company witness Grace. Company witness Grace accepted most of Staff's revisions and proposed alternate language in some cases. After Staff rebuttal testimony, the only revision to the proposed tariff language still contested was whether there should be any consideration of customer migration between Service Class ("S.C.") 2 and S.C. 3 and 4 in the approved tariff language as proposed by the Companies. Staff witness Ebrey opined that the Companies' proposal introduced unnecessary complication to the Rider VBA calculations, requesting the Companies provide additional explanation of the cause of the migration as well as potential for continued movement in its surrebuttal testimony. Staff Ex. 12.0 Corrected, p. 27. While the Companies provided an explanation of the customer switching that occurred in 2008 and 2010, they also acknowledged that customer switching may not occur at the levels

[16] Staff recognizes that under Section 9-202(a) of the PUA the Commission can set temporary rate schedules if it believes a utility is over earning. 220 ILCS 5/9-202(a).

seen in those 2 years. NS-PGL Ex. 45.0, p. 25. Therefore the Commission should approve the tariff changes as set forth in NS-PGL Ex. 45.5 and NS-PGL Ex. 45.6 except for those proposed by the Companies which provide consideration for customer switching between S.C.2, S.C. 3, and S.C. 4.

C. Rider ICR

1. Accumulated Deferred Income Taxes

Mr. Effron's proposal to modify the formula for calculating Rider ICR by including related deferred income taxes may have merit. Currently under Rider ICR, the Company begins recovering plant additions immediately without an associated reduction for ADIT. Ratepayers do not receive the benefit of the associated ADIT until the succeeding rate case. However, if adopted the proposal could overly complicate the recordkeeping for the ADIT associated with the plant additions recovered through Rider ICR. In the rate case, the Company would need to separately reflect the amount of ADIT related to its baseline level of investment for plant additions not subject to cost recovery under Rider ICR in its test year. That calculation could be affected by issues and disallowances still under litigation in the still open reconciliation proceeding. Splitting the ADIT between two different cost recovery mechanisms increases the complexity of the issue. Staff Ex. 10.0, pp. 22-23. Should the Commission agree with Mr. Effron's proposal, the Commission should require the Companies to account for ADIT for each individual plant addition included in ICR.

IX. COST OF SERVICE

A. Overview

Both North Shore and Peoples Gas provided a cost of service ("COS") study with their filings in their respective Schedules E-6. The COS Studies identify the revenues, costs and profitability for each class of service and are the partial basis for the Companies' proposed rate design. Generally, the Companies prepared the COS Studies utilizing three major steps: (1) cost functionalization; (2) cost classification; and (3) cost allocation of all the costs of the utility's system to customer classes. NS Ex. 13.0, pp. 2, 6 – 7 and PGL Ex. 13.0, pp. 2, 6 - 7.

B. Embedded Cost of Service Study

1. Uncontested Issues

a. Sufficiency of ECOSS for Rate Design

Staff witness Harden found both North Shore's and Peoples Gas' COS study to be an acceptable guidance tool for setting rates in these dockets. Staff Ex. 7.0, pp. 5, 8. Staff witness Harden further noted that the same methodologies were used in the Companies' 2009 rate case and the Commission approved their use. *Id.*

2. Contested Issues

a. Classification of Uncollectible Accounts Expenses Account No. 904

b. Classification of A&G Related to O&M

c. Classification of Fixed Costs

X. RATE DESIGN

A. Overview

The Companies stated in direct testimony that they are proposing to recover a greater portion of fixed costs through fixed charges, which do not vary with the volume of gas delivered to customers. NS Ex. 13.0, pp. 9 - 10 and PGL Ex. 13.0, p. 11. The Companies did not propose to change the current rate structure. Staff Ex. 7.0, p. 8.

Staff accepted the Companies' proposed rate design. However, Staff witness Harden further testified that the final rates approved by the Commission's Final Order in these dockets should be based on the approved revenue requirement for the Companies in the Commission's Final Order. Staff Ex. 7.0, p. 19.

B. General Rate Design

1. Allocation of Rate Increase

2. Uniform Numbering of Service Classifications

As demonstrated in Staff witness Harden's Table 1 from direct testimony, North Shore Gas and Peoples Gas, for the most part, have the same customer classes, but each Company has different service classification numbers ("S.C. Nos.") to identify customer classes. Staff Ex. 7.0, p. 3. In Docket Nos. 09-0166 and 09-0167, Staff recommended that to limit confusion for customers with accounts in both service territories, and to simplify the ratemaking process, it would be beneficial for the Companies to adopt a uniform set of S.C. Nos. In the Commission's Final Order at p.

211 of the Companies' 2009 rate case, the Commission accepted the Companies' proposal to assess their customer information systems to determine if they could implement uniform numbering of their service classifications.

In direct testimony in this docket, Companies' witness Valerie H. Grace stated that the Companies determined that changes would need to be made to their customer information systems for billing, bill print and data management; their accounting system, sales and revenue forecasting models; and interfaces linking data between all of these systems. NS Ex. 12.0, p. 28 and PGL Ex. 12.0, p. 31.

Companies' witness Grace also provided information that indicated that if uniformity were established, that it may not be sustainable for both Companies on a going-forward basis due to future tariff changes. The Companies' have determined that the time and expense necessary to make this change cannot be justified and therefore, the Companies did not propose to change to a uniform set of S.C. Nos. NS Ex. 12.0, pp. 28 - 29 and PGL Ex. 12.0, p. 31.

Staff accepted the Companies' review and findings that uniform numbering of the service classifications is not feasible at this time. However, Staff continued to recommend that the Commission order the Companies to analyze implementing uniform numbers in future rate cases. Ms. Harden noted that if changes or upgrades are made to the previously listed systems, this issue could be incorporated at the time of change, thereby limiting the time and expense of the change. Staff Ex. 7.0, pp. 4-5.

In rebuttal testimony in this docket, Companies' witness Grace indicated that the Companies would "agree to undertake this review." NS-PGL Ex. 28.0, p. 6.

Staff recommended that the Commission's final order in this matter reflect the agreement on this issue by Companies' witness Grace in her rebuttal testimony to undertake this review.

C. Service Classification Rate Design

1. Uncontested Issues

a. North Shore Service Classification No. 2

North Shore proposed an increase to the monthly customer charges for sales and transportation customers to recover more fixed costs in the monthly customer charges while moving the distribution charges for all three meter classes closer to the results of the COS Studies. NS Ex. 13.0, p. 18.

Staff recommended that North Shore's proposal to increase the customer charges for the sales and transportation customers to recover more fixed costs be approved. Staff testified that the Commission considers an increase in the fixed cost recovery through the fixed charge to be a benefit in the long run as stated in its Final Order of the Companies' 2009 rate case. ICC Docket Nos. 09-0166/09-0167 (Cons.), Order, January 21, 2010, pp. 217 – 218; Staff Ex. 7.0, p. 15.

North Shore proposed to decrease the first and second distribution blocks and increase the third block for the distribution charges for sales and transportation customers to better align revenues with underlying costs. NS Ex. 12.0, pp. 9, 11.

Staff recommended that North Shore's proposal to change the distribution charges for the sales and transportation customers be approved. Ms. Harden testified that the changes will move the distribution charges closer to the cost to provide the service. Ms. Harden further noted that due to the uncertainty as to whether the

Commission will adopt a permanent Rider VBA or switch to an SFV rate design in this docket, leaving the distribution charge structure unchanged is desirable at this time because of the possible bill impacts the Final Order's decision on this issue could have on the distribution charges is unknown at this time. Staff Ex. 7.0, p. 16.

b. North Shore Service Classification No. 3

North Shore proposed to set the monthly customer charge at the cost to provide the service which will result in a reduction from the current rate in each of these service classifications. North Shore proposed to increase the distribution charge and it proposed to eliminate the monthly standby service charge – per standby demand therm and recover the cost through a new charge under Rider SSC (Storage Service Charge). NS Ex. 12.0, p. 20.

Staff witness Harden recommended that the Company's proposal to set the monthly customer charge at the cost to provide the service for the Large Volume Demand Service customers be approved. Staff explained that the Company's proposal will maintain the monthly customer charges at the cost to provide service. A cost-based rate will send the proper price signals to customers. Sending proper price signals is especially important in a competitive environment, where customers can choose their commodity supplier. Staff Ex. 7.0, p. 17.

Ms. Harden recommended that North Shore's proposal to eliminate the standby service for the Large Volume Demand Service customers be approved if the Commission approves Rider SSC as recommended by Staff witness Sackett. Staff witness Sackett recommended that the costs recovered in the standby service charge be instead recovered through Rider SSC. If his recommendation is adopted, that would render the standby service charge moot. Staff Ex. 7.0, pp. 17 - 18.

Staff witness Harden recommended North Shore's proposed distribution charge for the Large Volume Demand Service customers be approved. Ms. Harden testified that it is appropriate to set all components of this class at the rates that will recover the cost of providing service to the Large Volume Demand Service customers. Staff Ex. 7.0, p. 18.

c. Peoples Gas Use of Equal Percentage of Embedded Cost Method ("EPECM")

Peoples Gas COS study provided the cost basis for determining the revenue requirement for the Small Residential and General Service classes using the Equal Percentage of Embedded Cost Method ("EPECM") to balance the rates for S.C. No. 1 to move toward cost against the rates of S.C. No. 2 customers. PGL Ex. 12.0, p. 9.

Peoples Gas used EPECM to proportionally allocate the Company's proposed revenue requirement changes to the Small Residential and General Service classes. Peoples Gas has used EPECM in its last four rate cases, Docket Nos. 91-0586, 95-0032, 07-0242 and 09-0167, and the Commission approved its use to set revenue requirements for these two customer classes. PGL Ex. 12.0, p. 9. Staff witness Harden testified that the EPECM provides a gradual increase toward the cost to provide service for the Small Residential class by balancing the increase with the General Service class. Staff Ex. 7.0, p. 7.

Ms. Harden found the use of EPECM to be appropriate for Peoples Gas. Proportionally allocating the changes over the two classes helps to mitigate the bill impact on Small Residential customers. Staff Ex. 7.0, p. 7.

d. Peoples Gas Service Classification No. 2

Peoples Gas proposed an increase to the monthly customer charges for sales and transportation customers to recover more fixed costs in the monthly customer charges while moving the distribution charges for all three meter classes closer to the results of the COS Study. PGL Ex. 13.0, p. 20.

Staff witness Harden recommended that Peoples Gas' proposal to increase the customer charges for the sales and transportation customers to recover more fixed costs be approved. Ms. Harden testified that the Commission considers an increase in the fixed cost recovery through the fixed charge to be a benefit in the long run as stated in its Final Order of the Companies' 2009 rate case. Docket Nos. 09-0166/09-0167 (Cons.), Order, January 21, 2010, pp. 217 – 218; Staff Ex. 7.0, p. 15.

Peoples Gas proposed to increase the first block and decrease the second and third blocks for the distribution charges for sales and transportation customers to better align revenues with underlying costs. PGL Ex. 12.0, pp. 11, 13.

Staff witness Harden recommended that Peoples Gas' proposal to change the distribution charges for the sales and transportation customers be approved. Ms. Harden testified that the changes will move the distribution charges closer to the cost to provide the service. She further stated that due to the uncertainty as to whether the Commission will adopt a permanent Rider VBA or switch to an SFV rate design in this docket, leaving the distribution charge structure unchanged is desirable at this time because of the possible bill impacts the Final Order's decision on this issue could have on the distribution charges is unknown at this time. Staff Ex. 7.0, p. 16.

e. Peoples Gas Service Classification No. 4

Peoples Gas proposed to set the monthly customer charge at the cost to provide the service which will result in a reduction from the current rate in each of these service classifications. The Company proposed to increase the distribution charge and they proposed to eliminate the monthly standby service charge – per standby demand therm and recover the cost through a new charge under Rider SSC (Storage Service Charge). PGL Ex. 12.0, p. 22.

Staff witness Harden recommended that Peoples Gas' proposal to set the monthly customer charge at the cost to provide the service for the Large Volume Demand Service customers be approved. Ms. Harden explained that that the proposal will maintain the monthly customer charges at the cost to provide service. A cost-based rate will send the proper price signals to customers. Sending proper price signals is especially important in a competitive environment, where customers can choose their commodity supplier. Staff Ex. 7.0, p. 17.

Ms. Harden recommended that Peoples Gas' proposal to eliminate the standby service for the Large Volume Demand Service customers be approved if the Commission approves Rider SSC as recommended by Staff witness Sackett. Staff witness Sackett recommended that the costs now recovered in the standby service charge, instead be recovered from Rider SSC. If his recommendation is adopted, that would render the standby service charge moot. Staff Ex. 7.0, pp. 17 - 18.

Staff witness Harden recommended Peoples Gas' proposed distribution charge for the Large Volume Demand Service customers be approved. Staff noted that it is appropriate to set all components of this class at the rates that will recover the cost of providing service to the Large Volume Demand Service customers. Staff Ex. 7.0, p. 18.

f. Peoples Gas Service Classification No. 8

Peoples Gas proposed to increase the monthly customer charge by 2% and increase the distribution charge by 13% for S.C. No. 8. The Company proposed to set this service classification at the cost to provide service as was done in the Companies' 2009 rate case. PGL Ex. 12.0, p. 23.

Staff witness Harden recommended approval of Peoples Gas' proposal to increase the monthly customer charge and the distribution charge for the Compressed Natural Gas Service. Ms. Harden explained that setting S.C. No. 8 at the cost to provide service is appropriate since it will recover the cost of providing service to the Compressed Natural Gas Service customers. Staff Ex. 7.0, p. 19.

2. Contested Issues – North Shore and Peoples Gas

a. Service Classification No. 1

The Companies proposed an increase to the monthly customer charges for sales and transportation customers and a decrease to the distribution charges for each of the two blocks. NS Ex. 13.0, p. 11 and PGL Ex. 13.0, p. 12. Companies' witness Grace stated that the fixed cost recovery numbers for North Shore's and Peoples Gas' S.C. No. 1 are proposed to increase to 69% and 62%. NS-PGL Ex. 28.0, pp. 5 – 6.

Staff witness Harden recommended that the Companies' proposal to increase the customer charges for the sales and transportation customers to recover more fixed costs for the Companies be approved. Ms. Harden stated that the Commission concluded in its Final Order in the 2009 rate case that a slight increase proposed by the Companies will be a benefit in the long run. ICC Docket Nos. 09-0166/09-0167 (Cons.), Order, January 21, 2010, pp. 217 – 218. Staff witness Harden concluded that the

Companies' proposal is consistent with the above ruling by the Commission. Staff Ex. 7.0, pp. 10 - 11.

Ms. Harden also recommended that the Companies' proposal to decrease the distribution charges for the sales and transportation customers be approved. Due to the uncertainty as to whether the Commission will adopt a permanent Rider VBA or an SFV rate design in this docket, a decision that will have an impact on the distribution charge, leaving the distribution charge structure unchanged at this time is desirable. Staff Ex. 7.0, pp. 11 - 12.

D. Tariffs – Other Non-Transportation Tariff Issues

1. Uncontested Issues - North Shore and Peoples Gas

a. Terms and Conditions of Service

Staff witness Harden testified that the "Companies stated that in the Final Order in the Companies' 2009 rate case the Commission found that the Companies should continue, in future rate cases, to move tariff charges steadily closer to cost. Docket Nos. 09-0166/09-0167 (Cons.), Order, January 21, 2010, p. 227. The Companies further stated in data request responses that the proposed increases are limited to approximately 20% – 25% over the current charges to address the Commission's directive in the Final Order." Staff Ex. 7.0, p. 24.

Staff witness Harden reviewed the documentation that the Companies provided and found the support to be an acceptable basis for the proposed tariff changes to the charges listed above. Ms. Harden recommended that the Commission approve all aspects of the Companies' proposals to increase the Service Activation Charges and the Reconnection Charges. Staff Ex. 7.0, p. 37.

b. Service Activation Charges

According to the Companies there are three categories of Service Activation Charges: (1) A succession turn-on; (2) a straight turn on; and (3) an additional charge to the straight turn-on for relighting more than four gas appliances during a straight turn-on. All of them recover a portion of costs relating to starting gas service at a premises and apply to customers moving into or within the Companies' service territories. NS Ex. 13.0, pp. 21 – 22 and PGL Ex. 13.0, p. 24.

North Shore proposed to increase the charge for a succession turn-on from $16.50 to $20.00, or a 21% increase. NS Schedule E-2, p. 18, Staff Ex. 7.0, p. 26.

Peoples Gas proposed to increase the charge for a succession turn-on from $15 to $18, or a 20% increase. PGL Schedule E-2, p. 16, Staff Ex. 7.0, p. 27.

North Shore proposed to increase the charge for a straight turn-on from $35 to $42, or a 20% increase. NS Schedule E-2, p. 18, Staff Ex. 7.0, p. 28.

Peoples Gas proposed to increase the Straight Turn-on from $25 to $30, or a 20% increase. PGL Schedule E-2, p. 16, Staff Ex. 7.0, p. 30.

The Companies proposed to increase the charge to relight more than four (4) appliances from $5 to $10 for both North Shore and Peoples Gas. NS Schedule E-2, p. 18 and PGL Schedule E-2, p. 16, Staff Ex. 7.0, p. 31.

Staff witness Harden reviewed the documentation that the Companies provided and found the support to be an acceptable basis for the proposed tariff changes to the charges listed above. Staff recommended that the Commission approve all aspects of the Companies' proposals to increase the Service Activation Charges and the Reconnection Charges. Staff Ex. 7.0, p. 37.

c. Service Reconnection Charges

The Companies proposed to increase the basic Reconnection Charge from $60 to $75, a 25% increase. NS Schedule E-2, p. 18 and PGL Schedule E-2, p. 16, Staff Ex. 7.0, p. 33.

The Companies proposed to increase the charge from $125 to $150 when service reconnection requires the meter to be reset. NS Schedule E-2, p. 18 and PGL Schedule E-2, p. 16, Staff Ex. 7.0, pp. 34-35.

The Companies proposed to increase the charge from $350 to $425 when service reconnection requires excavating at the main service pipe line. NS Schedule E-2, p. 18 and PGL Schedule E-2, p. 16. Staff Ex. 7.0, p. 36.

Staff witness Harden reviewed the documentation that the Companies provided and found the support to be an acceptable basis for the proposed tariff changes to the charges listed above. Staff recommended that the Commission approve all aspects of the Companies' proposals to increase the Service Activation Charges and the Reconnection Charges. Staff Ex. 7.0, p. 37.

d. Rider 2

e. Rider 9

E. Bill Impacts

The Companies' Schedule E-9 computed bill comparisons under the present rates and the rates as proposed by the Companies. Comparisons were shown for sales customers who take service solely under one service classification and also for transportation customers that take service under one classification as well as under a rider, such as Rider CFY as was previously discussed in my testimony. Staff Ex. 7.0, p. 21.

North Shore's Schedule E-9 showed a 38% increase for residential sales customers (30% for transportation customers) on a monthly bill for a customer with no usage. However, a residential customer with an average usage of 1,000 therms of gas per month would have a decrease of (-1%) for both sales and transportation customers. Staff Ex. 7.0, pp. 21-22.

Peoples Gas' Schedule E-9 showed a 40% increase for residential sales customers (39% for transportation customers) on the monthly bill for a customer with no usage. However, a residential sales customer with the average usage of 1,000 therms of gas per month would have an increase of 4% (3% for a transportation customer). Staff Ex. 7.0, p. 22.

Staff witness Harden concluded that the bill impacts generally result in higher percentage increases for customers with little or no usage than customers with an average usage of 1,000 therms of gas. The larger percentage increases for less usage reflect the Companies' proposal to recover a greater portion of fixed costs through fixed charges. Staff Ex. 7.0, p. 23.

XI. Transportation Issues

A. Overview

B. Uncontested Issues

1. Allowable Bank (AB) Calculation

2. Rider CFY

3. Rider AGG (except Aggregation Charge)

4. Rider SBO

C. Administrative Charges

D. Large Volume Transportation Program

1. Administrative Charges

The Commission should adjust test year expenses recovered in transportation tariffs downward by the amount proposed by Staff witness Sackett to reflect the Companies overly high projections of transportation expenses as evidenced by the Companies' consistent over budgeting of costs associated with transportation customers in each of the past three years.

The Companies' witness Mr. McKendry presented an exhibit that allocated the administrative charges to transportation customers and suppliers under the various transportation riders. PGL and NS Exs. 15.1. The Companies further provided the Gas Transportation Services ("GTS") budget for the future test year upon which these charges are based. Staff Ex. 9.0, Attachment A; Companies responses to Staff DRs

DAS 5.03, Atts. 1 and 2. Additionally, the Companies provided the budgeted and actual costs for the years 2008 -2010. Staff Ex. 9.0, Attachment B: Companies responses to Staff DRs DAS 5.04, Att. 1. This evidence shows that the Companies have over-budgeted in each of the past three years by an average of 19% including amounts from the Companies future test year used in the Companies' last rate case, 2010.

Staff witness Sackett proposed to reduce the budgeted amounts in PGL-NS Ex. 15.1 to reflect observed over-budgeting. He calculated a specific factor for each type of cost reflected in the budget. For labor with overhead the GTS expenses have been 17% *under* budget during 2008-2010. For non-labor with overhead the GTS expenses have been 67% *under* budget during 2008-2010. For IT with overhead, the GTS expenses have been 21% *under* budget during 2009-2010. Staff Ex. 9.0, pp. 7-8.

This evidence demonstrates that Companies have historically over-budgeted the inputs that make up the administrative charges for transportation suppliers. Mr. Sackett concluded that it is reasonably likely that the reductions that he proposed will prevent these suppliers from being over-charged as they have been since the last rate case. The Companies argue that the reason the costs are under budget is due to unanticipated events, NS-PGL Ex. 31.0, p. 3, however the net effect of these unanticipated events is that, in each area, in each year, the budgeted amount was high. The Companies provided no evidence that historical costs have *ever* been above the budgets.

There is disagreement between Staff and the Companies about what the correct test year administrative charges ought to be. Staff's position is that the ratepayers should pay for what administrative costs the company is *likely to incur*. The Companies believe that the test year should include any and all budgeted amounts. Staff Witness Sackett has calculated the percentage that these budget areas have been over for the last two years and applied these historical percentages for each budget area. Staff Ex. 18.0, p. 5

Because the Companies have historically had costs that have been under what they have budgeted, it is not reasonable to make ratepayers pay for the full amount of these forecasted expenses. Therefore, the Commission should order that the test year expenses be reduced by the amount proposed by Mr. Sackett.

2. Transportation Storage – Issues

Process of Change

In the previous North Shore and Peoples Gas rate cases, Docket Nos. 09-0166/0167 (Cons.), Staff proposed the unbundling of standby service under Rider SST from the storage rights. The Companies indicated that they were willing to work out the details of this process through a workshop. Docket Nos. 09-0166 & 0167 (Cons.), Order January 21, 2011, p. 235.

In the Final Order of that case, the Commission required "the Utilities to work with Staff and all other interested stakeholders to develop reasonable proposals for unbundling storage service" and to "file any agreed upon proposals in their next rate cases." Docket Nos. 09-0166 & 0167 (Cons.), Order January 21, 2011, p. 235.

In order to develop an unbundled storage service, the Companies entered into a process that included consultation with Staff and other interested parties. As part of their recommendations in this case, the Companies have included the only proposal which received universal support at the workshop, the recommendation to unbundle the Rider SST bank from standby service. Staff Ex. 9.0, p. 10.

The Companies have made five additional proposals in this case: (1) a stand-alone storage banking service under which customers select the amount of storage capacity, (2) monthly inventory targets with monthly cashouts, (3) daily injection and withdrawal limits with daily cashouts, (4) daily tolerance around the daily ranges and (5) eliminate the no-notice standby service. PGL Ex. 14.0, p. 18, NS Ex. 14.0, pp. 18-19. These proposals go far beyond the unbundling of Rider SST's standby service. Staff Ex. 9.0, p. 10.

After receiving stiff opposition in the 2007 rate case from Staff and intervenors, the Companies dropped most of their proposed restrictions in surrebuttal. Docket Nos. 07-0241 / 07-0242 (Cons.) North Shore/Peoples Gas Ex. TEZ-3.0 REV, p. 8. The Companies now have taken the Commission's directive to unbundle, which Staff believes was intended to expand flexibility for LVT customers, as an opportunity to make massive changes to their LVT programs that are even more restrictive[17] than what was proposed in the 2007 case. Staff Ex. 9.0, p. 16.

[17] "In response to other parties' criticisms during these proceedings, the Utilities modified their proposed changes to Rider SST (Selected Standby Transportation). PGL-NS TZ-3.0 at 9-10. In lieu of their original proposals for *daily injection and withdrawal limits,* the Utilities' revised Riders SST would limit a customer's monthly injections to 20% of AB converted to a daily injection limit, but there would not be additional daily limits on a customer's withdrawals from AB beyond limits currently in effect….The revised Riders SST would have new daily and monthly injection provisions, in the form of nomination limits, similar to proposed Rider FST, while retaining the existing daily and monthly withdrawal provisions. Rider SST would also have the *seasonal cycling requirements* applicable to proposed Rider FST." ICC Docket Nos. 07-0241/0242 (Cons.), Order, February 5, 2008, pp. 272-273, emphasis added. The Companies had proposed daily withdrawal and injection restrictions but only two inventory targets instead of 24.

Staff Witness Mr. Sackett testified in support of the unbundling and the elimination of standby proposals. However, he soundly rejected the additional daily and monthly restrictions. Staff Ex. 9.0, pp. 10-11. All transportation intervenors in this case have likewise rejected these restrictions. IIEC/CNEG Joint Ex. 1.0 and CNE-Gas Ex. 1.0.

Rider SST is a functional LVT Service with the flaw of having the storage access and standby linked. Breaking that link should not require that the service be altered. Mr. Sackett testified that "All other things being equal, the practical result of this directive [to unbundle storage services from standby service] would have been to *increase* flexibility for transportation customers by retaining the full flexibility currently in the Rider SST tariff and giving those customers an option to select the size of the bank independent of the level of standby." Staff Ex. 9.0, p. 11. However, the Companies' proposal gives a small amount of increased flexibility in the amount of annual storage capacity on the one hand and takes away both daily and monthly flexibility on the other.

Rider SBS is essentially Rider SST with the standby service removed. Therefore, there are many SST characteristics that are retained in the new rider, such as daily measured services, pools, nomination flexibility and Allowable Bank trading. PGL Ex. 14.0, p. 18, NS Ex. 14.0, p. 19. Rider SBS has a new subscription process that will enable customers to elect a level of bank capacity. PGL Ex. 14.0, p. 20, NS Ex. 14.0, p. 20. In addition to this necessary process, the Companies have also proposed daily injection and withdrawal parameters and monthly inventory targets. Staff witness Sackett proposed that the Commission remove these new parameters to make Rider

SBS similar to Rider SST. Staff Ex. 9.0, pp. 11-12. The only parameter that should be changed is the Critical Day ("CD") withdrawal amount. Staff Ex. 9.0, p. 25.

The Companies agreed to work with Staff to unbundle storage from standby but in the process they have attempted to start from scratch with the operational parameters that they could not justify changing under SST. The 2009 Final Order does not permit the Companies to reinvent the wheel in this respect.

SVT Differences

Staff witness Sackett notes that Small Volume Transportation ("SVT") programs differ significantly from the LVT programs currently in place for each Local Distribution Company ("LDC"), Nicor Gas, Peoples Gas and North Shore. There are two basic differences in the customers for each type of program and these diverse characteristics mean that the parameters of the two types of programs should be different. The result is that the LVT programs have traditionally had much more flexibility in the use of storage than the SVT programs at each LDC. Staff Ex. 9.0, p. 17.

Mr. Sackett testified that the two significant differences are metering and load characteristics. The SVT programs were designed for customers lacking daily demand meters and thus the daily usage of SVT customers must be estimated. This is in contrast to LVT customers whose daily usage is mostly known because most have a daily demand meter.[18] Staff Ex. 9.0, p. 17.

Additionally, while the individual transportation customers vary in size and load characteristics, the typical SVT customer is a residential customer with a relatively small

[18] This excludes Rider FST customers who have, and pay for, full backup.

load, low load factor, and peak usage that typically coincides with the system peak. By contrast the typical LVT customer is a commercial or industrial customer with a relatively large load, a higher load factor and a peak usage that is usually much less tied to the system peak because it is often a process-driven load. Because system peak is one of the primary drivers for storage, LVT and SVT customers use storage differently. Staff Ex. 9.0, p. 17-18.

The Companies seek to place a model that resulted in more flexible SVT parameters onto the LVT service with disastrous results. This is unprecedented and runs directly counter to the Commission's established approach to transportation. While the Companies pattern their SVT tariff after Nicor's SVT program, their proposed LVT tariff looks nothing like Nicor Gas' program.

LVT Restriction Attempts

Peoples Gas and North Shore proposals to significantly reduce the flexibility in both LVT services are not the first attempts by LDCs to do so. Each previous attempt was rejected in part by the Commission.

The first attempt was by Nicor Gas in its 2004 rate case (Docket No. 04-0779) to implement a single fall target injection target and a spring withdrawal target in its LVT program. Staff Ex. 9.0, p. 18. In that case, the Commission approved a single fall target injection target but rejected a spring withdrawal target. Order, September 20, 2005, Docket No. 04-0779 at 146.

Another attempt was by Peoples Gas and North Shore proposed significant reductions in storage flexibility in their 2007 rate cases. Docket Nos. 07-0241/0242 consolidated. When Peoples Gas and North Shore made some of the same proposals as Nicor Gas' in their 2007 rate case, the Commission referred back to the Nicor Gas' 2004 rate case as a guideline on the appropriate balance between transportation customers and sales customers. The Order below is instructive in this case,

> In Nicor we approved a fall injection target but not a spring withdrawal target. The Commission concluded that the former was a valid operational requirement that would not unduly burden transportation customers, but the latter was not. Nicor, Docket No. 04-0779, Order at 146. We are not persuaded to approve a different regime in these dockets. The Utilities generally assert that —the storage and standby rights of each Utility's transportation customers need to be shaped to be consistent with each Utility's individual gas supply portfolio, and each Utility needs to have an annual mechanism to adjust those rights as its individual gas supply portfolio changes That is not enough to outweigh the considerable difficulties the seasonal cycling requirements will present for transportation customers. E.g., CNEG Init. Br. at 20-24. While we are willing to subordinate those difficulties to the Utilities' operational needs during the heating season, the balance tips in the transportation customers' favor in the spring….
>
> The Commission also observes that the Utilities strongly emphasize the cycling requirements they face with respect to leased storage facilities. Without intending to minimize in any way the significance of those requirements, we see that the larger volume of stored gas managed by Peoples Gas resides in Manlove Field, where Peoples Gas establishes its own cycling schedule. Thus, most of the Utilities' own storage flexibility is constrained by the general need to recycle Manlove, not by storage leases. That fact, in turn, allows some latitude when balancing the competing and equally legitimate needs of the Utilities and the transporters.
>
> Accordingly, injection season requirements of 70% and 75% of AB are approved for, respectively, Peoples Gas and North Shore, while seasonal withdrawal requirements are disapproved.

ICC Docket Nos. 07-0241/0242 (Cons.), Order, February 5, 2008, p. 276.

In that 2007 case, the Commission also approved nomination limits during the injection season for Riders FST and SST. The Commission Order again noted the necessity of striking a balance between managing the system and transportation customers desire to efficiently manage their gas supply,

> The Commission readily acknowledges the serious and complex responsibilities the Utilities bear with respect to management of their storage assets. We also recognize the desire of large commercial gas end-users to manage gas supply in a manner that efficiently contributes to their enterprises. We are also committed to encouraging competitive gas supply, so that customers enjoy the benefits competition can provide. Our task is to optimally balance these interests.

Id., p. 278.

In both of the orders cited above, the Commission addresses the balance between these "competing and equally legitimate needs." The instant proposal drastically alters the status quo. In doing so the Companies propose to reduce the transportation customers' current flexibility and tip the balance which the Commission established in 2007.

The Companies have failed to make a convincing case for the changes that they propose, reverting back to the some of the same arguments that the Commission rejected in 2007. Staff Ex. 9.0, p. 20. In addition to these same arguments, the Companies provide a new analysis that they claim alters the landscape.

The Companies propose to apply their SVT framework directly to Riders SBS. PGL Ex. 14.0, pp. 22-23, NS Ex. 14.0, p. 22. To ease the effect of these restrictions, the Companies propose to allow a Daily Balancing Tolerance ("DBT") around their daily injection and withdrawal parameters. PGL Ex. 14.0, pp. 25-26, NS Ex. 14.0, p. 26.

Furthermore, while the Commission was hesitant to allow the Companies to impose a single withdrawal target for one month in the fall and rejected the accompanying spring target, the Companies now propose injection and withdrawal targets for every single month of the year. Staff Ex. 9.0, p. 22.

The Companies propose taking away the flexibility transporters currently have with daily maximum injection and withdrawal rates and monthly inventory targets from Rider SST customers. The Companies apparently consider reviving the DBT to be "a direct subsidy from sales customers." PGL Ex. 14.0, pp. 25-26, NS Ex. 14.0, p. 27. By the same rationale, the taking of this flexibility from transportation customers and giving it to sales customers in the first place would likewise be a direct subsidy.

Basis for Changes

The Companies' witness Mr. Connery claims that the two factors motivating the proposed changes are system reliability concerns and the economic interests of sales customers. PGL Ex. 14.0, pp. 12-13, NS Ex. 14.0, p. 13. The Companies attempt to convince the Commission to make drastic operational changes for operational concerns that do not exist by blurring the line between these distinct concerns. As Mr. Sackett notes in his direct testimony, system integrity concerns and economic concerns of sales customers are best considered separately because they are really two different issues and the tariffs in effect at this time have different set of tools for the two concerns. Staff Ex. 9.0, p. 12.

No System Harm

The Companies have shown no cause for increased system concerns. The system has not been compromised because the Companies have the tariff's system protections. The tariffs currently have tools that enable the Companies to adequately manage the system and prevent compromise including declaring Critical Days ("CD") or invoking delivery restrictions. Staff Ex. 9.0, p. 13. The Companies' claim that, "As a result of proper management, coordination with upstream pipelines, and by imposing limits on allowed deliveries the Company has been able to keep its system from being compromised." Companies responses to Staff DR DAS 3.03d. Mr. Sackett points out that protecting against *potential* harm can result in unwarranted restrictions, which reduces transportation customers' options because they become unnecessarily constrained. Staff Ex. 9.0, p. 14.

If the changes in LVT cannot be justified by system concerns, the Companies have to justify them based on the economic effects transportation customers' actions on sales customers. However, the Companies clearly state that they do not believe that the burden of proof is upon them or that they should have to show evidence of harm. The Companies believe that all they must do is point out circumstances where it might happen and that should be sufficient for the Commission to approve the roll out of a daily metered LVT service that is significantly more restrictive than its predecessor. These changes will be detrimental to LVT without any showing that they will benefit sales customers.

To justify restricting transportation customers' choices to this extent, the Companies should not provide examples of such harm, but rather an assessment of the total net impact on sales customers. Barring a showing of this type, the Commission should reject these proposed restrictions.

The Companies do not attempt to provide evidence that Sales customers are harmed by the current rules. "The Utilities have not tried to quantify whether "net" economic harm occurs to sales customers." NS-PGL Ex. 46.0, p. 4. The Companies should demonstrate to the Commission a net harm to sales customers before it makes changes to the nature of LVT service in the Companies' service territories.

Additionally, while the Companies maintain that transportation customers are economically driven – NS-PGL Ex. 30.0, p. 16, they freely acknowledge that these actions may actually benefit sales customers from time to time. Staff Cross Ex. 9. Thus, the *potential* effect of these actions is not really this issue but rather the *net* effect.

Since the Companies balance the system through changes in purchases for sales customers –NS-PGL Ex. 30. 24 and NS-PGL Ex. 46.0, pp. 4, 11-13, it is inevitable that these purchases will respond to the actions of transportation customers. Thus any transportation service will necessarily require such a design; It is not a feature that will be "corrected" by the Companies' proposals. Each Company balances its system for the benefit of all customers, including transportation customers, using all assets at their disposal. There are not "sales assets" and "transportation assets." On any given day, transportation customers may use sales customers' *capacity*, and on the next day, sales customers may use transportation customers' *capacity*.

Model is (fatally) flawed - Diversity

Mr. Sackett describes a gas operational concept know as diversity:

> Diversity in this context refers to the property that not all customers use storage in the same way on any given day. For example, during injection season on any given day, some customers may inject up to the maximum limits while others may inject less while still others may actually withdraw from their storage banks. Because of this diversity of actions, a maximum injection level per customer based on all customers injecting their maximum quantities would result in less than the maximum for the group being injected. Diversity during withdrawal season has a similar effect. The utility aggregates all customers together when it plans how to deliver service to all customers. (Attachment C: Companies responses to Staff DR DAS 3.21) But each *customer* is different. Diversity allows individual customers to have more proportionately more flexibility than is possible for the group as a whole.

Staff Ex. 9.0, p. 23.

Diversity is not accounted for by the Companies' model, and they have adjusted their operational parameters for diversity only in an ad hoc manner in response to Staff comments. NS-PGL Ex. 30.0, p. 15. Diversity is not a "likelihood" but rather an empirical fact. Given that the effect of diversity is significant enough to discredit the need for monthly targets, any model that does not consider it should be rejected out of hand.

All adjustments that account for diversity are made with no analysis or empirical basis. The Companies' witness Connery claims to have taken diversity into account. He relaxes his daily injection and withdrawal parameters slightly to "account" for this diversity. PGL Ex. 14.0, pp. 12-13, NS Ex. 14.0, p. 13. There is no reason to conclude that the adjustments that the Companies proposed adequately reflect the diversity on the system. As shown below, diversity is a significant factor. The amount of potential protection that their proposal offers comes at the price of a large amount of flexibility for transportation customers. Mr. Sackett believes that this reduces the efficiency of the transportation program without proportionate benefits for sales customers. Staff Ex. 9.0, pp. 23-24.

Evidence of Historical Inventory Levels

There is more diversity than the Companies' proposal accounts for. Diversity is a concept that applies to both daily and monthly parameters.

CNE witness Kawczynski analyzed the Companies' data to produce CNE-Gas Exhibits 1.4 and 1.5, which show the monthly inventory balances for all transportation customers as a group for the heating years 2007/2008 to 2009/2010 compared to the individual minimum and maximum target inventories proposed by the Companies. CNE-Gas - Ex. 1.0, p. 21.

The Companies' witness Connery wrongly reinterprets CNE-Gas Exhibits 1.4 and 1.5 as supporting individual restrictions, because he alleges that they do not burden transportation customers. For example, he argues, "The Utilities believe that Mr. Kawczynski's testimony and particularly the graphs in CNE-Gas Ex. 1.4 and CNE-Gas Ex. 1.5 highlight the Utilities' need for the monthly ranges and further demonstrate that they are not a burden for the transportation customers." NS-PGL 30.0, p. 16. This is incorrect. He reaches this erroneous conclusion because he does not recognize that his proposed restrictions can impose significant burdens on the individual customers even when the group as a whole is within the proposed parameters. Staff Ex. 18.0, pp. 8-10.

Furthermore, Mr. Connery concludes that, "the Utilities believe that the few months of balances which fall above the proposed ranges show that the LVT group utilized storage capacity paid for and belonging to sales customers. If economics drove the LVT balances (which would be fully inclusive of all diversity) to those levels then sales customers suffered economic harm due to the unavailability of that space." NS-PGL 30.0, p. 16. However, Mr. Connery did not demonstrate that "economics" drove transportation customers to operate above the Companies' proposed target inventory levels. In fact, if "economics" were the driving factor, North Shore customers, operating with the same "economics," would not have managed to keep their balances within the proposed target range without any formal requirements. Staff Ex. 18.0, p. 9.

Mr. Connery then changes his tune in his surrebuttal testimony. "The specific exogenous factors or lack of influence are not important." NS-PGL Ex. 46.0, p. 5. However, Mr. Connery stated in rebuttal testimony that the economic harm was dependent on those factors being economic (i.e. economic opportunities that sales customers forego which would not be realized *if the factors were economic ones*). NS-PGL 30.0, p. 16. The Companies acknowledge that sales customers are not economically harmed during months when the inventories are within the tariff parameters. Staff Cross Ex. 10. The exhibits also show that sales customers have use of transportation customers' capacity most of the time.

Despite the Companies repeated attempts to use selected days for proof that sales customers were economically harmed, Mr. Connery did not show that there was a net economic harm to sales customers. There is simply no evidence that this harm occurs over time in one direction or another. Staff Ex. 18.0, p. 9.

The graphs shown in these two exhibits fully reflect the diversity of transportation customers, and they show that transportation customers, as a group, are largely keeping their inventories well within the range proposed. Therefore, monthly storage inventory targets are not necessary. The Companies acknowledge that "CNE-Gas Ex. 1.5 shows that the actual LVT activity for North Shore—without the influence of monthly ranges—fits comfortably within the proposed ranges." NS-PGL 30.0, p. 16. Additionally, CNE-Gas Exhibit 1.4 shows that for the past 4 years, the actual LVT activity for People Gas—without the influence of monthly ranges—fits comfortably within the proposed ranges *with one brief exception*. Staff Ex. 18.0, p. 10.

Mr. Sackett points out the disparity that exists between the model and the actual diversity. He states,

> These exhibits, which according to the Companies "fully reflect diversity," show that the divergence between Mr. Connery's model and how diversity actually works is not minor or insignificant, but rather it is large enough to dismiss the need for the monthly parameters altogether. Rather than acknowledge that these exhibits demonstrate that there is no need for monthly storage targets, the Companies undermine their position by calling into question the other so- called "requirements" of their systems. Furthermore, it appears that this is the first time that the Companies have been confronted with the actual diversity on their system. Diversity should have been directly modeled in order to determine if the massive changes that the Companies are proposing are necessary. The evidence shows that they are not.

Staff Ex. 18.0, p. 11.

Further, the Companies' model does not reflect that the Companies' tariffs allow them to declare Critical Days ("CDs"), and the delivery restrictions which mitigate any potential harm to sales customers. However, the data provided by the Companies indicates that the tools currently in place are more than adequate to protect system integrity from actions taken by transportation customers. Mr. Connery's model does not account for these tools, so he introduces other parameters into his model to protect the system. Staff Ex. 9.0, p. 25.

Finally, Mr. Connery presented the load factors of various groups of customers NS-PGL Ex. 30.0, p. 8. However, the data confirms Mr. Sackett's claims because it shows that LVT customers have load that is relatively more process driven and less coincident with the system peak. Staff Ex. 9.0, p. 12.

Staff recommends that the Commission conclude that the Companies have not demonstrated the need for their proposed monthly storage limits and daily delivery restrictions. Therefore, the Commission should reject their proposals.

3. Associated Rider Modifications

a. Rider SBS/SST

b. Rider FST

Rider FST is the Companies LVT tariff for smaller transportation customers. It has more flexibility than Rider SST and is monthly balanced. The Companies have proposed to add certain restrictions on to Rider FST to keep it in line with their proposals for SBS parameters. Specifically they have argued that the analytical framework that applies to SBS should apply to FST. They propose to incorporate monthly inventory targets and revised CD and OFO parameters. The Companies have proposed that Rider FST customers must deliver 27% and 39 % of their MDCQ on a CD and OFO Supply Shortage Day. PGL Ex. 14.0, pp. 29-31, NS Ex. 14.0, p. 30-31.

The Companies allege revisions to unbundle the storage bank in Rider SBS are required because the underlying assets that supported partial standby under Rider SST are no longer linked to the Rider SBS bank. NS-PGL Ex. 30.0, p. 7. However, the same rationale does not apply to Rider FST, whose underlying assets have not changed. Yet the Companies have argued that Rider FST customers should also suffer a similar fate to Rider SST by losing as much flexibility as can possibly apply. Staff Ex. 18.0, p. 14.

The proposed parameters would make Rider FST, Full Standby Transportation Service, *not full standby*, because customers would be required to deliver 27% for Peoples Gas and 39% for North Shore of the customer's MDQ on an OFO Supply Shortage Day or a Critical Day Supply Shortage Day. Staff Ex. 18.0. pp. 14-15.

Further, Mr. Sackett pointed out that under the Companies base proposal, Rider FST customers are billed the same Standby Demand Charge as the current tariff provides (the Demand Gas Charge times MDQ) but the benefits from that standby are significantly reduced. The restriction of the ability to withdraw gas on an OFO Supply Shortage Day or Critical Day Supply Shortage Day is an inappropriate and unprecedented reduction of the standby rights that transportation customers have for access to system gas. It appears that the only purpose for the restrictions is to align the rules that Rider FST customers must follow with the rules for the other programs. Staff Ex. 18.0. p. 16.

The Companies subsequently proposed to reduce the non-storage portion of the charges to Rider FST customers by 20%. NS-PGL Ex. 46.0. p. 10. Mr. Connery believes that the customers will only be restricted on 5% of the days. However, this appears to be another inadequate attempt by the Companies to fix a significant problem with a token solution. His estimates of actual constraints ignore the fact that those customers' rights have been reduced by 27% and 39% year-round. Thus, the effect will be felt on all days.

Because these customers and the intervenor that has FST customers (CNE-Gas) have not had a chance to rebut the Companies' surrebuttal testimony proposal to reduce certain costs, the effect that this will have on FST customers is not known. However, if those customers subscribe to full standby so that they can have full standby on a Critical Day, then the value of this service would be fundamentally reduced.. Since the Companies are currently providing this full standby service year round the underlying assets have not changed. Staff recommends that the Commission reject the Supply Shortage Day delivery requirement for Rider FST.

In the alternative, if the Commission determines that it is necessary to turn "Full Standby" into something less than its name implies, then a broader reduction in costs is warranted. Staff recommends that the amount that these costs are reduced be equal to the amount that those customers are required to deliver for each utility.

c. Rider P

d. Rider SSC

Ms. Grace proposes to recover the underground storage costs from sales customers under a new Rider Storage Service Charge ("SSC") using a new charge called the Storage Service Charge ("SSC") - PGL Ex. 12.0, pp. 46, NS Ex. 12.0, p. 42 - and she proposes to recover underground storage costs from transportation customers under Rider SSC using the Storage Banking Service ("SBS") charge. PGL Ex. 12.0, pp. 46, NS Ex. 12.0, pp. 46-47.

Staff witness Sackett recommends that this rider be approved. Staff Ex. 9.0, p. 29.

e. Transition Riders

E. Small Volume Transportation Program (Choices for You^{SM} or "CFY")

1. Aggregation Charge

IGS witness Mr. Parisi's recommended that Small Volume Transportation ("SVT") administrative costs should be recovered from all customers *eligible* for Choices For You ("CFY"). IGS Ex. 1.0, p. 31. Staff witness Sackett countered that the costs for these programs, while over-budgeted, have been and continue to be for costs exclusive to transportation programs. Staff believes that there is no reason for sales customers to bear any portion of this cost.

Mr. Parisi claims that in the workshop process ordered by the Commission, the Companies refused consensus. IGS Ex. 1.0, p. 33. However, the Companies were not required to agree with the SVT, rather they were to implement certain operational parameters upon which there was consensus. Staff does not agree with the SVT suppliers on this issue and Staff has not supported this issue in the past rate case.

Mr. Parisi argues further that since the Commission views Nicor Gas' SVT Customer Select as more successful than CFY, the Utilities should follow Nicor's program design. IGS Ex. 1.0, p. 33. However, the directive to model the Companies' SVT programs after Nicor's was specifically directed at the operational parameters, Order, Docket Nos. 09-0166 & 0167 (cons.) at 253-254, which the Companies embraced. Staff Ex. 9.0.0, p. 15.

2. Purchase of Receivables (withdrawn)

Interstate Gas Supply of Illinois ("IGS"), through its witness Mr. Parisi, proposed that the Commission order the Utilities to begin a Purchase of Receivable ("POR") program for Choices for You ("CFY") suppliers. In a POR program, the retail seller sells its receivables, the bills that its customers need to pay, to the utility at a discount. In return, the utility retains the entire amount collected from the bills. Staff opposed the proposal, and, while it recognizes that IGS withdrew its proposal, it would nevertheless like to point out a few things to complete the record. Staff Ex. 19.0, pp. 2-3.

Mr. Parisi claimed that a POR will lower the overall costs that ratepayers incur. IGS Ex. 1.0, pp. 16-17. However, he provided no empirical support to bolster his claims concerning lower prices and decreased collections costs. Staff recommended that the Commission not implement a POR program for the Utilities. Staff Ex. 19.0, pp. 2-3. First, there is a chance that total costs may increase if the total amount of ARGSs charges is greater than the comparable utility gas charges. Second, under the recently amended Section 5/19-130, the Commission's Office of Retail Market Development ("ORMD") must compile a report that investigates the state of retail gas competition in Illinois, including the barriers to development of competition and any other relevant information. In compiling this report, the ORMD must "gather input from all interested parties[.]" PUA Section 5/19-130, Public Act 097-0223. This presents a better opportunity for ARGSs and other parties to advance proposals to further the development of competition in the retail gas markets. Id. pp. 3-5.

XII. CONCLUSION

Staff respectfully requests that the Illinois Commerce Commission approve Staff's recommendations in this consolidated docket.

Respectfully submitted,

JOHN C. FEELEY
MICHAEL LANNON
NICOLE LUCKEY
Office of General Counsel
Illinois Commerce Commission
160 North LaSalle Street, Suite C-800
Chicago, IL 60601
Phone: (312) 793-2877
Fax: (312) 793-1556
jfeeley@icc.illinois.gov
mlannon@icc.illinois.gov
nluckey@icc.illinois.gov

Counsel for the Staff of the
Illinois Commerce Commission

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